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STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota

FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDED ORDER

This matter came on for evidentiary hearing before Administrative Law Judge Richard C. Luis on July 20-22, 2005 in the Small Hearing Room at the offices of the Public Utilities Commission in St. Paul, Minnesota. Public hearings were held by videoconference on April 19, 2005. The afternoon videoconference was conducted between St. Paul, Crookston, Fergus Falls, and Marshall. The evening videoconference was conducted between Minneapolis, Crookston, Fergus Falls, and Marshall.

At the conclusion of the evidentiary hearing, a briefing schedule was established. Posthearing briefs were filed on September 21, 2005, and reply briefs were filed on October 5, 2005. The hearing record closed on October 5, 2005.

Brian M. Meloy, Attorney at Law, Leonard, Street and Deinard, P.A., 150 South Fifth Street, Suite 2300, Minneapolis, MN 55402 and Donald R. Ball, Assistant Vice President - Regulatory Affairs, 400 N. Fourth Street, Bismarck, ND 58501-4092 appeared on behalf of the Great Plains Natural Gas Company (Great Plains or the Company).

Vincent Chavez, Gas Division Supervisor for the Minnesota Department of Commerce (Department) and Julia Anderson, Assistant Attorney General, 445 Minnesota Street, Suite 1400, Saint Paul, MN 55101, appeared on behalf of the Department.

Clark Kaml, Jerry Dasinger, Bret Ecknes, and Janet Gonzales, 121 Seventh Place East, Suite 350, St. Paul, Minnesota, appeared on behalf of the Staff of the Minnesota Public Utilities Commission (Commission). Kari Zipka, Assistant Attorney General, 445 Minnesota Street, Suite 1400, Saint Paul, MN 55101, also appeared on behalf of the Commission.

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission ("Commission") and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed according to the schedule which the Commission will announce. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply (if any), and an original and 15 copies of each document should be filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

STATEMENT OF ISSUES

In this matter, the Commission has directed that an evidentiary record be established with regard to the following issues:

(1) Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings by the Company?

(2) Is the rate design proposed by the Company reasonable?

(3) Are the Company's proposed capital structure and return on equity reasonable?

(4) Are the Company's service extensions and service extension policies consistent with applicable statutes and rules, Commission directives, and the public interest?

(5) Are the Company's cost allocation policies and processes consistent with applicable statutes and rules, Commission directives, and the public interest?

(6) Are the Company's customer charge proposals consistent with applicable statutes and rules, Commission directives, and the public interest?

In addition, the Commission required filings regarding service line extensions and other tariff issues that do not necessarily have an impact on rates.

Based on all the proceedings herein, the Administrative Law Judge makes the following:

FINDINGS OF FACT

A. Jurisdictional-Procedural Background

1. On September 7, 2004, Great Plains filed a Petition with the Commission, under Minn. Stat. § 216B.16, for an increase in natural gas rates of $1,436,026 (overall, approximately a 4.0 percent increase) over the company's current rates. Great Plains also filed a Petition for Interim Rates in the amount of $1,436,026.[1]

2. On November 1, 2004, the Commission issued an Order allowing Great Plains to complete its petition as of a future date.[2] Under that Order, the proposed rate increase was suspended until the Commission determined the reasonableness of the proposed rates. Also on that date the Commission issued a Notice and Order for Hearing, directing that a contested case hearing be convened to determine the reasonableness of the rate changes proposed by Great Plains. The rate design, capital structure, return on equity, service extensions and policies, cost allocation policies and procedures, and customer charge proposals are other issues that the Commission indicated should be addressed.[3]

3. The Commission's Executive Secretary certified Great Plains' filing as complete on November 12, 2004. The revised Petition requested an increase in natural gas rates of $1,365,682 (overall, approximately a 3.8 percent increase) over the company's current rates.[4]

4. On November 23, 2004, the Commission issued an Order setting interim rates, authorizing Great Plains to collect approximately $1,300,000 in additional annual revenues effective January 10, 2005.[5] Great Plains is collecting interim rates subject to refund to the extent that the interim rates are in excess of the final rates determined by the Commission.[6]

5. On December 14, 2004, a prehearing conference was held before Administrative Law Judge Richard C. Luis in St. Paul, Minnesota. No Petitions to

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[1] Company Ex. 1, Binder 1, Notice of Change in Rates.
[2] ***ITMO a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota***, PUC Docket No. G-004/GR-04-1487 (Order Accepting Rate Case Filing as of Future Completion Date and Suspending Rates issued November 1, 2004)(***Great Plains***).
[3] *Id.* (Notice and Order for Hearing issued November 1, 2004).
[4] Company Ex. 6, Imsdahl Revised Direct, at 6.
[5] ***Great Plains***, (Order Setting Interim Rates issued November 23, 2004) (http://www.puc.state.mn.us/docs/orders/04-0154.pdf).
[6] *Id.*, at 3 (Order Setting Interim Rates issued November 23, 2004).

Intervene were filed at the hearing. Petitions to Intervene were received from Ag Processing, Inc. and Dahlen, Berg & Company. Both of these petitions were granted and the petitioners were admitted as parties to this matter.

6. On May 6, 2005, Great Plains filed a Motion to Amend Prefiled Testimony and Request for a Shortened Response Time. On May 12, 2005, the ALJ issued the Second Prehearing Order conditionally granting the Company's Motion. Due to the substantive nature of the revisions to the Company's testimony, the Department was permitted additional discovery and the opportunity to file additional written surrebuttal testimony. The Second Prehearing Order also continued the hearing from its scheduled date of May 16, 2005. Great Plains' Motion was granted with the condition that by May 18, 2005, Great Plains submit a motion requesting a waiver of the timelines in Minn. Stat. § 216B.16, subd. 2.

7. The Company filed its motion requesting waiver of timelines. Great Plains revised its motion to unconditionally waive its rights to implement rates. With the revision, Great Plains' request for a waiver of timelines was granted by the ALJ June 3, 2005. This matter came on for evidentiary hearing July 20, 2005 and continued through July 22, 2005. The parties filed posthearing initial briefs, reply briefs, and proposed findings of fact. The hearing record closed on October 5, 2005, with the receipt of the last filing.

B. Summary of Public Comments

8. Afternoon and evening public hearings were conducted by means of video conferences in the afternoon and evening of April 19, 2005. Company representatives, Dale Lusti of the Department of Commerce and members of the public appeared at video conference locations in Fergus Falls, Marshall and Crookston.

9. In Fergus Falls, business owner James Palmer complained that his bills had gotten "outrageous" since the time Great Plains was "taken over" by MDU. Madeline Herman appeared at Fergus Falls and asserted that the fact so few people appeared for public oral comment was because consumers "felt helpless". Ms. Herman complained that the company's proposal to raise its basic service charge for residential customers from $5.50 to $8.00 would lead to confusion about how much of one's bill was based on consumption of gas. In Marshall, James Brunsven, representing a mobile/modular home manufacturer, asked that the bills received by his company (from 12 different meters) be consolidated into one bill in order to simplify bookkeeping.

10. The ALJ received several letters from the ratepaying public before the deadline for written comment on April 25, 2005. One writer said he was "fed up" with "phantom" charges for distribution costs and franchise fees. Another alleged company used its natural gas bills to subsidize the discounts it offered in its non-regulated appliance sales operation. Other complaints included that the company's 3.8 percent increase request was higher than the rate of inflation, and that senior citizens on fixed incomes find heating costs to be a burden during the winter. The financial officer for the Marshall School District cautioned that school districts, which are restricted for the next

three years to "flat-line funding," could not afford to budget for boosts in gas prices at the level requested by Great Plains. Another writer complained about being put into a different customer class, with a higher monthly customer charge, because of having built a new house that utilizes an electric heat pump as its primary source of energy. Mr. Palmer, a speaker in Fergus Falls, wrote that natural gas utilities serving nearby communities such as Detroit Lakes, Perham, Alexandria and Morris were cheaper than Great Plains. He also requested that billing be measured utilizing mcf units rather than by dekatherms (dk), for "simplicity" reasons. He also wants to be able to purchase gas in the summer, when the commodity is cheaper, to "store" for winter use.

C. Description of the Company

11. Until 2000, Great Plains was an investor-owned utility, providing natural gas to 18 western Minnesota communities and one North Dakota community. Great Plains served approximately 20,000 Minnesota customers and 2,000 North Dakota customers.

12. In June 2000, the Commission approved a merger between Great Plains and Montana-Dakota Utilities Resources Group, Inc. (MDU). MDU is a Delaware-incorporated diversified natural resource company. MDU has a utilities division, structured as a subsidiary, Montana-Dakota Utilities Co. (MD Utilities) that provides natural gas to over 200,000 customers and electric service to over 100,000 customers in North Dakota, South Dakota, Wyoming, and Montana.

13. The remainder of MDU is structured under Centennial Energy Resources, LLC (Centennial) which is another wholly-owned subsidiary of the parent corporation. Centennial has business interests in pipeline and energy services, natural gas and oil production, financing and insurance, and provides construction services to the utility industry. The Knife River Corporation (wholly-owned by Centennial) owns contracting, construction, and raw material suppliers in nine states. Centennial has international business holdings, including independent power production in Brazil.[7]

14. Since the merger, MDU operates the natural gas utility service of Great Plains as a division of MD Utilities.[8] By way of comparison, Great Plains' natural gas distribution assets comprise four-tenths of one percent (0.4%) of MDU.[9] At the same time, Great Plains accounts for 1.7% of MDU's total revenues.[10] Great Plains estimates that it serves 20,900 customers in Minnesota, 86 percent residential, 13 percent firm general service, and 1 percent interruptible sales and transportation.[11] The parent corporation's headquarters are located in Bismark, North Dakota. Great Plains' operations are directed from Fergus Falls, Minnesota.

[7] Company Ex. 1, Vol. III, Statement F, Schedule F-1, at 21.
[8] Great Plains issues no stock, since it is a division of MDU.
[9] Company Exhibit 8, Direct Testimony of J. Stephen Gaske ("Gaske Direct"), at 4, JSG-2, Schedule 2.
[10] Company Ex. 8, Gaske Direct, at 28.
[11] Company Ex. 6, Imsdahl Revised Direct, at 3.

15. In addition to its natural gas distribution business, Great Plains operates an unregulated energy service and repair (S&R) business, which offers appliance sales, repair and maintenance for a variety of heating ventilation and air conditioning (HVAC) installations and other appliances.[12] Great Plains' last rate increase in Minnesota was granted in 2003.[13]

D. Natural Gas Service Areas

16. Great Plains' natural gas customers in Minnesota are divided between three service areas, denominated Crookston, North-4, and South-13.[14] These three areas have historically had different rate structures. These differences were recognized in Great Plains' last rate increase, approved by the Commission on October 9, 2003.[15] In 2003, the Commission approved a modification to Great Plains' rate structure that recognized the differences in the historical rate structures and adopted a consolidation plan for the Crookston and North-4 service areas. The consolidation was ordered to take place in two steps, one at 18 months from the ***2003 Rate Order*** and the other at three years from that Order.[16]

17. Great Plains' petition for a rate increase neglected to account for the Commission's consolidation schedule established in the ***2003 Rate Order***. After the situation was recognized, Great Plains submitted revised proposals for its rate increase, reflecting the status of the consolidation and the impact of the final stage of the consolidation.

E. Great Plains' Capital Structure

18. Since Great Plains is a division of MDU, the Company lacks a readily defined capital structure. In similar circumstances, a hypothetical capital structure has been substituted for the assessment of proposed rates.[17] For the purposes of this rate proceeding, Great Plains originally proposed the following capital structure:

Great Plains 2005 Projected Capital Structure[18]

Long-Term Debt	43.535%
Preferred Stock	4.557%
Common Stock Equity	51.908%

[12] Tr. Vol. 1, (Imsdahl), at 27-29.
[13] ***In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota***, PUC Docket No. G-004/GR-02-1682 (Order Accepting and Adopting Settlement issued October 9, 2003)("***2003 Rate Order***").
[14] The naming convention describes the primary area or numbers of cities served.
[15] ***2003 Rate Order***.
[16] ***2003 Rate Order***, at 7.
[17] Department Ex. 27, Griffing Direct, at 12.
[18] Company Ex. 1, Vol. III, Statement D, at 3.

19. The Department and the Company do not dispute that the foregoing capital structure is appropriate. Disputes over the impact of this structure on particular portions of the proposed rates will be discussed in subsequent Findings.

F. Existing Rate Structure

20. Prior to approval of Great Plains' interim rate, the Company's natural gas rate structure consisted of the wholesale cost, basic charges, and a delivery rate. The basic charge and delivery rate constitute the delivery charge portion of the customer bill. The wholesale cost to Great Plains for the natural gas sold to customers is passed through in customer bills without markup. Thus, the delivery charge must account for Great Plains' costs of providing natural gas service and Great Plains' return.

Basic Service Charge

21. The basic service charge is the amount paid monthly by any customer connected to Great Plains' gas distribution system. This charge is paid independent of gas usage. For residential customers the charge is $5.50 per month. For firm general service customers, the charge is $20.00 per month. For commercial classes of customers receiving interruptible and transport services from Great Plains, the customer basic charges for sales are either $100.00 or $200.00 and for transport are either $175.00 or $250.00, depending on customer class. [19]

Delivery Rate

22. The remaining portion of the customer bill is the delivery rate.[20] This charge is calculated by multiplying the therms in the natural gas purchased by an established rate.[21] For Crookston residential customers, the current rate is $2.1447 per dk.[22] For North-4 residential customers, that rate is $1.163.[23] For South-13 residential customers, that rate is $1.3881.[24] Commercial classes generally pay lower delivery rates due to the volume of gas consumed.[25]

G. Test Year

23. Great Plains proposed using the per books financial information for the calendar-year base period ending December 31, 2003 as the basis for projecting a test year (2005) to determine the revenue deficiency to be remedied by this proceeding.[26] The projected test year methodology has been accepted in past rate cases, where the

[19] Ex. 2, Vol. I, Aberle Revised Direct, at 9, lines 2-9.
[20] Ex. 2, Vol. I, Aberle Revised Direct, at 10.
[21] One therm is equal to 100,000 BTU's.
[22] Ex. 2, Revised Tariff Sheets.
[23] *Id*.
[24] *Id*.
[25] *Id*.
[26] Company Ex. 18, Mulkern Revised Direct, at 2.

projected test years can be shown to produce reliable results.[27] The Department did not object to the Company's proposal to use a projected test year in this case. The Commission established interim rates effective January 2005.[28]

24. While the Department did not object to the use of the test year method, the Department did object to Great Plains' projected test year budget. The Department asserted that Great Plains failed to show that its expenses in its base test year are reasonable. The Company used a projected average 2005 test year. The 2005 test year is developed from the 2003 actual results and further adjusted by Great Plains.

25. Great Plains' last rate case was resolved in 2003, when the Commission approved a settlement that increased Great Plains' annual revenue requirement by $1.1 million, an increase of approximately 4.65%.[29] The rate established by the ***2003 Rate Order*** used a 2003 projected test year.[30] The Department pointed out that Great Plains did not use its projected 2003 test year expenses (which were approved, with adjustments, by the Commission in the ***2003 Rate Order***), to build its projected 2005 test year proposal. The Department expressed concern that the actual 2003 income statement included expenses that the Commission found to be not recoverable from ratepayers. This could lead to the incorporation of unrecoverable expenses in the rate base for Great Plains in future years, thereby imposing those costs on ratepayers in contravention of the Commission's rulings.

26. Great Plains asserts that the primary reasons for this rate case are increased operating expenses and increased investment in rate base above the levels authorized in the last case.[31] Through its investigation, the Department concluded that the primary driver of the identified revenue deficiency is an increase in operating expenses. The Department acknowledged that the Company had increased investments in rate base, but the Department characterized the effect of rate base adjustments on the 2005 revenue requirement as constituting approximately 8 percent of the requested increase in this docket. The Department estimated the other operations and maintenance (O&M) expenses (not including cost of gas) as being responsible for 84 percent of the 2005 increased revenue requirement.[32] The Department also noted that the actual 2003 rate base also was very similar to that projected in the Company's last rate case. Thus, Great Plains' revenue deficiency did not arise through insufficient sales volumes.

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[27] *See* ***ITMO the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota****,* Docket No. E-002/GR-91-1 (Findings Of Fact, Conclusions Of Law And Order issued November 27, 1991).

[28] ***Great Plains***, (Order Setting Interim Rates issued November 23, 2004) (http://www.puc.state.mn.us/docs/orders/04-0154.pdf).

[29] ***In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota***, Docket No. G-004/GR-02-1682 (Order Accepting and Adopting Settlement issued October 9, 2003)("***2003 Rate Order***").

[30] Department Ex. 73, Lusti Direct, at 6.

[31] Company Ex. 6, Imsdahl Revised Direct, at 7,

[32] Department Ex. 73, Lusti Direct, DVL-18.

27. The Department observed that, when considered on a percentage basis, the Company's requested revenue deficiency compared to existing rates is more than twice those of two other regulated utilities with rate increase requests pending before the Commission.[33] Those other utilities had not requested rate relief for seven and nine years, respectively. The Department expected that any general economic cause for Great Plains' additional rate increase request would have affected the other two utilities as well. With all three utilities likely to face similar changes in particular items such as insurance or medical expenses, no particular increases appeared to explain the increase in Great Plains' claimed revenue deficiency.

28. The only observed difference between the three utilities was the merger of Great Plains with MDU. As described by a Department witness:

> [T]he only thing that I can specifically . . . identify [as] a difference that may have occurred is the Commission merger order[.]" The differences between the proposed 2003 test year and the 2003 actual results "are, you know, to a large degree unexplainable." Tr. Vol. 4 at 470 (Lusti).

29. Great Plains asserted that the increase in its Minnesota natural gas rates is needed because its cost of providing natural gas service is not adequately reflected in currently authorized rates.[34] Great Plains maintains that decreasing natural gas consumption by its customers, and increases in operating expenses, including labor and other operation and maintenance expenses, has resulted in a significant revenue deficiency. Absent an increase in rates, Great Plains asserts that it cannot continue to provide reliable natural gas service to its Minnesota customers or offer a reasonable rate of return to investors.

<u>Merger Order</u>

30. The Commission approved the merger between Great Plains and MDU in 2000. The Commission approved the merger and imposed the following conditions, among others, on the post-merger Great Plains:

> Petitioners shall hold Minnesota ratepayers harmless as to any increase in Great Plains' cost of service resulting from the merger.
>
> Petitioners shall not seek recovery of merger-related costs (transaction and transition) from Minnesota ratepayers in any future rate case.
>
> Petitioners shall not seek recovery of the acquisition adjustment, including goodwill, resulting from this merger from Minnesota ratepayers in any future rate case.

[33] Department Initial Brief, at 27.

[34] Company Exhibit No. 6, Revised Direct Testimony of Bruce T. Imsdahl ("Imsdahl Direct") at page 4, lines 14-18.

> In Great Plains' next Minnesota rate case, petitioners shall not seek recovery of corporate cost allocations exceeding Great Plains' comparable corporate costs for the twelve month period ending December 31, 1999. Comparable costs are those relating to corporate services of the type and scope that Great Plains currently has, adjusted for inflation.
>
> Great Plains shall maintain a detailed record of the description and amount of each of its 1999 corporate costs until the end of its next Minnesota rate case.[35]

31. The Commission also cited its ongoing docket on cost allocations, ***ITMO an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities***,[36] and included, at the Department's urging, the following language:

> The Department noted that approving the merger would not constitute approving MDU 's corporate cost allocation practices and suggested reminding MDU that Minnesota cost allocation standards have been set by Order in an earlier industry-wide proceeding.[37]

32. Great Plains pointed out that this rate proceeding is not the "next" proceeding within the meaning of the ***Merger Order***. But this being the second rate proceeding does not resolve the issue. The Commission established a discrete limit on corporate costs that could be allocated by MDU to Great Plains. That discrete limit was limited to the next rate case. While not expressly stated, the Commission's ***Merger Order*** has the effect of the "next" proceeding, establishing a baseline of reasonable costs for the post-merger Great Plains derived from the costs incurred by the stand-alone Great Plains. Future cost increases would be assessed for reasonableness by their relationship to the established baseline costs.

33. By using projected 2003 costs for the "next" rate proceeding, and much higher actual 2003 costs in this proceeding, Great Plains has sidestepped the baseline that was to have been established under the process set out in the ***Merger Order***. Great Plains bears the burden of showing that the actual 2003 costs are reasonable and that the resulting rates to be paid by Minnesota ratepayers are just and reasonable.[38]

34. In its ***Merger Order***, the Commission also required MDU/Great Plains to "hold ratepayers harmless as to any increase in Great Plains' cost of service resulting from the merger."[39] There is no time limit on that condition. The "resulting from the merger" limitation imposes an independent restriction on what costs can be allocated where, as here, functions formerly conducted by officers and employees of the pre-

[35] ***ITMO a Request by Great Plains Natural Gas Company for Approval to Merge Great Plains Energy Corp. and its Subsidiary, Great Plains Natural Gas Company, with MDU Resources Group, Inc.***, GR-004/PA-00-184 (Order Accepting Stipulation and Agreement and Approving Merger Subject to Conditions issued June 13, 2000)("***Merger Order***").
[36] G,E-999/CI-90-1008 (generally "***Appliance Docket***").
[37] ***Merger Order***, at 5.
[38] Minn. Stat. § 216B.03 (2004).
[39] ***Merger Order***, at 5.

merger Great Plains are now conducted by officers and employees of MDU, without direct identification of time and duties.

35. MDU is free to structure its corporate operations in any manner it pleases. But this freedom does not mean that the costs of that structure are allowable as allocated costs to Great Plains. The Company has asserted that "targeted efforts to increase operational efficiencies and minimize costs" were made.[40] But at the same time, the actual costs identified by Great Plains in 2003 are far higher than the comparable corporate costs for premerger Great Plains for the same year.[41] Great Plains must show that the costs to be allocated are reasonable. This can be done by demonstrating, on a functional basis, that the duties and responsibilities of an allocated position are directly replacing a position that existed with the pre-merger Great Plains. Similarly, new costs that arise independently of the merger that would have been costs incurred by a stand-alone Great Plains are appropriately allocated in rate setting proceedings under the provisions of the ***Merger Order***.

<u>Impact of Merger Order on 2003 Test Year</u>

36. The Commission found the merger between Great Plains and MDU to be in the public interest, conditioned on holding "Minnesota ratepayers harmless as to any increase in Great Plains' cost of service resulting from the merger." To the extent any cost identified by Great Plains results from the merger, that cost cannot be included in the Great Plains' rate base. This limitation is independent of the corporate cost allocation condition that strictly limited those costs to the level of the pre-merger Great Plains until the "next rate case." The Commission's intent to impose this independent condition was made clear by the separate reference to corporate cost allocation limitations.

37. The Department has objected to Great Plains' use of actual costs that the Commission found to be not recoverable from ratepayers. The methodology of rate setting relies on establishing reasonable and recoverable expenses to determine what revenue requirements result in an appropriate rate of return. Incorporation of unrecoverable expenses in the rate base for Great Plains would result in costs found to be unrecoverable being imposed on Minnesota ratepayers in future years.[42]

[40] Ex. 14, Morehouse Revised Rebuttal, at 16.
[41] For example, actual O&M expenses for 2003 exceeded the Commission-approved expenses for that year by $404,552, approximately 9 percent. Department Ex. 73, Lusti Direct, DVL-19; and Department Ex. 77, Lusti Supp. Surrebuttal, at 18.
[42] In effect, inclusion of costs found to be nonrecoverable by a regulated utility in a subsequently established rate base merely defers those costs to ratepayers in the near future. Such a practice would severely impair the Commission's ability to assess rates for reasonableness.

H. Test Year Revenue, Expenses and Operating Income

38. Great Plains and the Department agreed that the Company's rate base was $10,321,629.[43] The parties' differing calculations of operating revenues and operating expenses are as follows:

INCOME STATEMENT

	Great Plains	Department
Operating Revenues		
Sales	$35,362,220	$36,608,114
Transportation	311,845	357,435
Other	263,562	263,562
Total Revenues	35,937,627	37,229,111
Operating Expenses		
Operation and Maintenance		
Cost of Gas	28,582,025	29,642,482
Other O&M	5,618,937	5,052,945
Total O&M	34,200,962	34,695,427
Depreciation	1,016,677	1,016,677
Taxes Other Than Income	581,304	581,304
Current Income Taxes	110,740	440,467
Deferred Income Taxes	(209,038)	(209,038)
Total Expenses	35,700,645	36,524,837
Operating Income	$236,982	$704,274
Rate Base	$10,321,629	$10,321,629
Rate of Return	2.296%	6.823%

[44]

39. From these differing starting points, the parties each calculated Great Plains' revenue deficiency as follows:

CALCULATION OF REVENUE DEFICIENCY

	Great Plains	Department
Rate Base	$10,321,629	$10,321,629
Required Rate of Return	9.628%	8.960%
Required Income	$993,766	$924,818

[43] Company Reply Brief, Attachment A.
[44] Company Reply Brief, Attachment A.

Operating Income	236,982	704,274
Income Deficiency	$756,784	$220,544
Gross Revenue Conversion Factor	1.705611	1.705611
Revenue Deficiency	$1,290,780	$376,163
% Increase[45]	3.6%	1.0%

40. As set out in the foregoing Findings, Great Plains initially requested an increase in revenue of $1,365,748. Great Plains agreed with the Department regarding adjustments (discussed below) to bad debt expense, advertising, late payment fees, and other operating revenue, cumulatively totaling $74,968. With those adjustments Great Plains' requested revenue increase totaled $1,290,780.[46] The Department disputed additional expense amounts (discussed below), and applying those items to the lower return on equity (ROE) figure resulted in a total adjustment of $989,586, which would further reduce the allowable revenue increase to $376,163.[47]

I. Sales Forecast

41. The rate setting methodology relies on dividing estimated future costs over estimated future sales to determine the actual rates to be charged. Thus, volumetric sales estimates are critical to the appropriate rates to be set. Overestimating sales can result in the Company not receiving an appropriate return on investment. Underestimating sales can result in the Company receiving a higher rate of return than that authorized by the Commission. The sales forecasted by the Company and the Department for the 2005 test year differed by over one million dollars. Differing methods were used for forecasting Residential and Firm Volume sales and Interruptible and Transportation customer sales. Each method will be discussed separately.

Residential and Firm General Sales Forecasts

42. As with its last rate case, Great Plains relied on the normalization of actual volumes, by performing a 36-month regression analysis by rate area for each of the Residential and Firm rate classes. After calculating sales volumes for the residential and firm general categories by weather normalizing the 2003 historical usage, the Company-normalized volumetric (dk) use per bill was then calculated and multiplied by the number of 2004 projected bills to arrive at the projected volumes. The Company then calculated the normalized 2004 dk use per bill and multiplied by the number of 2005 projected bills to arrive at the projected volumes for the test year. As a final step

[45] Company Reply Brief, Attachment A.
[46] Company Reply Brief, Attachment A, at 3.
[47] Department Ex. 77, Lusti Supp. Surrebuttal, DVL-SS-1; Department Initial Brief, at 156; Company Reply Brief, Attachment A, at 3.

to its test-year project, Great Plains applied a 0.50 percent conservation deflator starting in September 2004, to reflect ongoing conservation by customers.[48]

43. The Department analyzed the Company's forecast and concluded that the calculations used by Great Plains likely underestimate the Residential and Firm General sales volumes for the Crookston, North-4 and South-13 service areas.[49] The Department used available Company-provided data adjusted for billing cycles from 1999 through 2001 that had been accepted by the Commission in the ***2003 Rate Order*** and used the Company-provided billing cycle adjusted data from 2002 through 2004. The Department developed an alternative regression analysis model that predicted higher residential and firm sales volumes.

44. Great Plains has introduced no specific studies, workpapers, or documents relating to Great Plains' customers and service territory in Minnesota to support the propriety of using its conservation deflator.[50] As set out in the testimony supporting the use of the deflator, the factor is introduced merely to make the proposed and normalized volumes for 2003 and 2004 a closer fit. This is not an adequate demonstration for introduction of a factor to affect forecast volumes over the span of years for which this rate will be effective. A factor this important to the overall calculation of the Company's sales forecast cannot be assumed to be reasonable. Some showing using objective data is required.

45. The Department assessed the Company's regression models and data for the Residential and Firm General classes for all three service areas and added a time trend variable to capture any observable effect of conservation.[51] The modeling demonstrated that any effects of conservation on customer usage are not reflected in the Company's models and that the use of a conservation deflator is not supported by the evidence.[52] The Department has shown affirmatively that the use of a conservation deflator is unreasonable.[53]

46. The Department compared the regression results using a larger sample size (72 data points to the Company's 36) and the same 60° F base used by Great Plains for the degree-day calculations in the model.[54] The Department's analysis

[48] Company Ex. 19, Mulkern Revised Rebuttal, at page 10; Department Ex. 49, Shah Direct, at 11.
[49] *See* Department Ex. 51, Shah Supp. Surrebuttal, SS-2.
[50] Department Ex. 49, Shah Direct, at 12.
[51] Department Ex. 51, Shah Supp. Surrebuttal, SS-8.
[52] Department Ex. 49, Shah Direct, at 13.
[53] Great Plains argues that:

> Even assuming the accuracy of Mr. Shah's contention that using 72-months of data in his regression analysis is "more reasonable," there is a not a requirement that Great Plains' firm volumes forecast be the "most reasonable," particularly where the Department is unable to refute the reasonableness of the Company's approach. Company Initial Brief, at 74.

As a general matter, the more reasonable forecast will prevail in a contested case proceeding. In this matter, the Department has affirmatively refuted the Company's forecasting approach. The Department's approach addresses the methodological problems of the Company's forecast and is the only reasonable basis in the record upon which to forecast the Company's test year sales volumes for residential and firm volume customers.
[54] Department Ex. 50, Shah Surrebuttal, at 8-11 and SS-2.

showed that, in general, Great Plains underestimated the sales volumes for the Residential and Firm General classes. The Department's sales forecast for the Residential and Firm General rate classes is reasonable and should be adopted.

Interruptible and Transport Volume Sales Forecasts

47. Great Plains also prepared a forecast of the sales volumes for interruptible customers. Sales to interruptible customers and transportation volumes account for approximately one half of Great Plains sales by volume.[55] For the forecast, the Company completed a customer-by-customer regression analysis using current information. The Company maintains that its method more accurately determines interruptible sales and transportation volumes to be expected in the 2005 test year. As Great Plains described the process:

> Great Plains reviewed each customer's use for a three year period and determined the customers whose volumes were weather sensitive by plotting the consumption and temperature data and running a regression for each customer. Where it was determined that the customer's gas usage was not weather sensitive, the actual 2003 volumes were reviewed to determine if they were reflective of current conditions. If they were, the actual 2003 volumes were used.
>
> For the customers whose consumption was weather sensitive, Great Plains used individual customer regressions based on data for the period 2001-2003 to adjust the actual 2003 volumes to reflect normal weather. This is consistent with the methodology used to determine weather normalized firm volumes.
>
> Great Plains then calculated revenue using the actual rate schedules under which each customer is taking service.[56]

48. The Department objected to the interruptible customer forecasting methodology used by Great Plains. Unlike the forecast for Residential and Firm General classes, where aggregate volumes were used, Great Plains chose to forecast usage by each of the Company's 177 interruptible customers individually. The methodology as to how each individual customer was treated was not provided to the Department. At the hearing, the Department asked directly what decision criteria were used to adjust the forecasts for individual customers. Great Plains responded by describing the categories of information used. There was no description as to how this information was applied to any individual customer to a degree of specificity that would permit the Department to replicate the Company's calculation.[57] Great Plains' responses to the Department's discovery on this issue were similarly vague.[58]

49. In the absence of the methodology used to arrive at the Company's forecast, the Department conducted an analysis of the results provided in that forecast.

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[55] Tr. Vol. 1, Mulkern Testimony, at 169-170.
[56] Company Ex. 20, Mulkern Revised Rebuttal, at page 18, lines 4-18.
[57] *See* Tr. Vol. 1, Mulkern Testimony, at 163-169.
[58] Department Ex. 51, Shah Supp. Surrebuttal, at 7-10

The Department conducted a regression analysis using the data provided by Great Plains. The Department's regression analysis of Great Plains' forecast showed that 38 percent of the interruptible sales and transportation customers were predicted to have a "negative constant."[59] This result is not a result of weather sensitivity, since that was determined by Great Plains' analyst through usage, not a regression analysis.[60] This negative constant result also appears in Great Plains' workpapers.[61] In the context of forecasting sales, the Company's forecast predicted that 38 percent of Great Plains' interruptible or transportation customers would either be supplying Great Plains with gas or using less than no gas.[62] Great Plains asserted that this result is merely one statistic that can be supplanted by a better forecasting method.[63] In the context of a sales analysis, a negative constant shows that some problem exists with the regression analysis conducted.[64]

50. Great Plains responded to these criticisms, asserting that the Company:

> [had] analyzed "the nature of the customer's business (i.e. school, hospital, manufacturing, grain drying) and the customer's consumption pattern. Broadening the review process to consider customer characteristics provides a better analysis than merely running a statistical correlation." Through this analysis and a review of the results of the R squared component of the analysis, in each instance in which a regression analysis resulted in a negative constant, Great Plains satisfied itself that its projections were accurate.[65]

51. The issue in this matter is not whether the Company, the Department, or the ALJ are satisfied with the accuracy of any particular forecast. What must be determined is whether the Commission can conclude that the charges being borne by Minnesota ratepayers are "just and reasonable."[66] Transparency in forecasting methodology ensures that the calculation has not been manipulated to favor a desired outcome. Statistical reliability provides some reassurance that an appropriate methodology has been used. Both of these factors are important in arriving at a conclusion that proposed rates meet the "just and reasonable" standard. The methodology used by Great Plains relies on individual adjustments, to an undisclosed degree and based on unidentified criteria, to customer usage estimates. This approach is not transparent and the method used cannot be replicated for analysis. Using that methodology, 38 percent of the customers in the class being analyzed returned anomalous results. The Department has demonstrated that Great Plains' forecast for interruptible sales and transportation volumes is unreliable.

[59] Department Ex. 50, Shah Surrebuttal, at 9-10.
[60] Tr. Vol. 1, at 161 (Mulkern) (regression analysis only used with heating sensitive loads).
[61] Company Ex. 3, Schedule C-1, at 60-65 ("Constant" column). The numbers in parentheses in that column are negative numbers.
[62] Department Ex. 51, Shah Supp. Surrebuttal, at 4, 9-10.
[63] Company Initial Brief, at 78.
[64] Tr. Vol. 1, at 183-184 (Mulkern) (negative constant does not make sense).
[65] Company Initial Brief, at 78 (record citations omitted).
[66] Minn. Stat. § 216B.03 (2004).

52. As an alternative to dismissing this proceeding, the Department proposed using the same methodology and volume information that supported the ***2003 Rate Order***. Using this approach, the volumes for the Crookston, North-4, and South-13 areas that were used to project the 2003 test year revenues would be applied for determining the 2005 test year revenues.[67]

53. Great Plains asserts that the Department's forecast does not reasonably reflect expected customer conservation, and uses outdated interruptible volumes. The Company contends that these factors do not reflect current conditions, and Great Plains maintains that this forecast would substantially overstate test year revenue that the Company would likely have the opportunity to achieve.[68]

54. The Department recognized that the interruptible sales and transportation volumes currently reflected in rates have not been updated by either party this case. The Department conducted a "rough comparison" of Great Plains' actual volumes for 2003 and 2004, to the volumes that were approved in the ***2003 Rate Order***.[69] The comparison suggested that the use of those volumes would be reasonable.[70] The forecast volumes in the ***2003 Rate Order*** were higher than the volumes actually sold by Great Plains, but the Company's actual volumes have been increasing. The actual volumes sold can reasonably be expected to be comparable to those volumes forecast in the earlier matter. On the record of this proceeding, only the Department's approach provides a reasonable basis for rate setting. Applying those volumes results in an estimated sales revenue adjustment of $1,291,484 (not including late payment fees and other revenue, discussed elsewhere), and an increase of $1,060,457 in O&M expenses.[71]

J. Allowable Expenses

55. The other side of the balance sheet for establishing just and reasonable rates is the level of allowable expenses that may be used to establish the revenue requirements for the Company. These allowable expenses, when compared to the anticipated revenue from the existing rates applied to the sales forecast, determine the amount of anticipated revenue deficiency that must be made up through increases in rates allocated among the customer classes.

Cost of Capital

56. The Commission must set rates that are just and reasonable. Minn. Stat. § 216B.03 (2004). The determination of reasonableness involves a balancing of consumer and utility interests. A reasonable rate enables a public utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in capital markets. Minn. Stat. § 216B.16, subd. 6 (2004) recognizes this

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[67] Department Ex. 49, Shah Direct, at 20.
[68] Company Initial Brief, at 12.
[69] Department Ex. 50, Shah Surrebuttal, at 5.
[70] Department Ex. 50, Shah Surrebuttal, at 5.
[71] Department Ex. 75, Lusti Surrebuttal, DVL-S-5.

principle when it defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment. Minnesota law requires that any doubt as to reasonableness must be resolved in favor of the consumer. Minn. Stat. § 216B.03 (2004).

57. A regulated utility's return must be reasonably sufficient to assure financial soundness and provide the utility adequate means to raise capital.[72] The investor requirement for a return sufficient to cover operating expenses includes debt service, dividends on stock and continued assurance in the utility's ability to maintain credit and attract capital.[73] To be just and reasonable, a return should be similar to returns on investments in other businesses having corresponding risk.[74]

58. The parties agreed that the initially proposed capital structure describing the hypothetical division between Great Plains' long-term debt, short-term debt, and equity would be used for setting rates in this proceeding. Great Plains requested a return on equity (ROE) figure of 11.00%. The Department disagreed with the proposed ROE and recommended an ROE of 9.72%.

59. Great Plains relied upon the analysis of Dr. Stephen Gaske to support its proposed ROE. In calculating the proposed ROE, Dr. Gaske employed a Discounted Cash Flow ("DCF") analysis.[75] Dr. Gaske maintained that an ROE of 11.0% reflects the cost of capital for an investment with the unique risks faced by the Company and is the level of return required to attract new capital on reasonable terms.[76]

60. To arrive at the 11.0% figure, Dr. Gaske calculated a range of ROEs from his comparison group and then adjusted the resulting average to account for asserted unique risks faced by Great Plains that include: (1) extremely small size, (2) lack of geographic and customer diversity, (3) rate design limitations, and (4) historically low to negative returns.[77]

61. Using the ROE figure of 11.0% for common equity, Dr. Gaske calculated a rate of return (ROR) proposed for Great Plains of 9.63%, derived as follows:

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[72] ***Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia***, 262 U.S. 679, 693 (1923).

[73] ***Federal Power Commission v. Hope Natural Gas Co.***, 320 U.S. 591 (1944).

[74] *Id*. at 603.

[75] Dr. Gaske described DCF analysis as follows:

The DCF method reflects the assumption that the market price of a share of stock represents the discounted present value of the stream of all future dividends. The DCF method suggests that investors in common stocks expect to realize returns from two sources that investors expect the firm to pay: a current dividend yield, plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method therefore is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a company. Company Ex. 8**,** Gaske Direct, at 10.

[76] Company Ex. 8**,** Gaske Direct, at 3.

[77] Company Initial Brief, at 11.

Great Plains Cost of Capital Proposal

Component	Percent of Total	Cost Rate	Weighted ROR
Long-Term Debt	43.54%	8.52%	3.708%
Short-Term Debt	0.00%	0.00%	0.00%
Common Stock Equity	51.91%	11.00%	5.71%
Preferred Stock Equity	4.56%	4.61%	0.21%
Total Rate of Return (ROR)			9.63%[78]

62. The Department did not dispute the cost of capital calculations for long-term debt, short-term debt, or preferred stock equity.[79] The Department only disputed the Company's requested cost of common equity (ROE) and resulting overall rate of return (ROR). The Department asserted that three components of Great Plains' DCF analysis do not support the Company's conclusions. These three components are: 1) the assessment of the comparison group; 2) overemphasis on the impact of risk; and 3) calculation of the flotation-cost adjustment.[80] The Department also objected to Dr. Gaske's assertion that a utility such as Great Plains must demonstrate an ROE of 10 percent or higher to overcome a psychological barrier displayed by investors to investing in companies with returns below 10 percent.

Comparison Group

63. Both Dr. Gaske and Dr. Griffing, the Department's Cost of Capital witness, began their DCF analyses by compiling lists of proxy companies considered to be similar to the hypothetical Great Plains stand-alone corporation.[81] Their comparison groups were as follows:

Gaske Group	Griffing Group
AGL Resources	AGL Resources, Inc
Atmos Energy	Atmos Energy
Energen	Cascade Natural Gas Corp.
KeySpan Corp.	Laclede Group, Inc.
Laclede Group, Inc.	New Jersey Resources

[78] Company Ex. 8, Gaske Direct, at 3.
[79] Department Exhibit 23, Direct Testimony of Marlon Griffing ("Griffing Direct"), at 17 and 31.
[80] Department Initial Brief, at 13-14.
[81] Since there is no actual Great Plains stock, the DCF methodology requires finding actively-traded companies that are similar to the corporate unit being assessed for ROE and ROR. Tr. Vol. 2, at 231-233.

NICOR, Inc.	Northwest Natural Gas Co.
Northwest Natural Gas	Peoples Energy Group
Peoples Energy	Piedmont Natural Gas Co.
Piedmont Natural Gas	South Jersey Industries
South Jersey Industries	
WGL Holdings	

64. Companies were included by Dr. Gaske in his group if these companies were: 1) listed by Value Line as natural gas distribution companies; 2) had a bond rating of investment grade; and 3) for which Zack's long-term growth rate projections were available.[82] Dr. Gaske examined the members of his proxy group and found a range of ROR from 8.9% to 11.3%.[83] From this information, he calculated a median ROR of 9.8% and an average of 9.9% for his comparison group.[84] All but two companies in Dr. Gaske's comparison group had both an investor required return and a cost of capital of less than 10.0%. Only two of these companies, Atmos Energy and Keyspan, had an investor required return and a cost of capital of more than 10.0%.[85] Dr. Gaske concluded particular characteristics of Great Plains (primarily regarding risk) required an ROE of 11.0%.[86]

65. Dr. Griffing assembled his proxy group by finding companies whose bond ratings were similar to that of Great Plains' parent corporation, MDU Resources, Inc. From those, only companies that had more than 65 percent of their earnings from natural gas operations ("earnings screen") were considered. The nine companies that passed the earnings screen comprise the Griffing group.

66. Great Plains criticized the Department's approach in establishing a comparison group and the methodology used in arriving at a proposed ROE. Great Plains maintained that the use of the bond rating for MDU Resources, Inc. is inappropriate, because that bond rating necessarily understates the risk inherent in Great Plains' business. That risk was emphasized by noting Great Plains' small size, relatively undiversified customer base, and lack of weather normalization.[87]

67. The Department noted that the bond rating of MDU Resources, Inc. reflects that the corporation is engaged in unregulated business operations in the competitive marketplace. In those areas of business, MDU Resources, Inc. lacks the market power

[82] Company Ex. 8, Gaske Direct, at 14.
[83] Company Ex. 8, Gaske Direct, at 34.
[84] Company Ex. 8, Gaske Direct, JSG-2, Schedule 2, at 7.
[85] *Id*.
[86] Company Ex. 8, Gaske Direct, at 35.
[87] Tr. Vol. 1, at 69-76.

of a monopoly. This situation is necessarily reflected in the bond rating of MDU Resources, Inc. To the extent that Great Plains has higher risk than other similar regulated utilities of larger size, the risk is adequately reflected the bond rating used by Dr. Griffing.

68. Dr. Griffing established a range of ROEs. The numerical midpoint of the range was chosen as the ROE most reflective of the ROE appropriate for Great Plains.[88] Great Plains objected to the range established, in part because Keyspan was excluded from Dr. Griffing's comparison group.

69. Keyspan is much larger than any of the other companies in either comparison group. That company has three times the assets, three times the operating revenue, and four times the operating income of any other company in either group.[89] In addition to the large size of Keyspan, it did not meet the earnings screen used by Dr. Griffing to assure similarity of business to that of Great Plains.[90] Keyspan was properly excluded from the comparison group to determine ROE.

70. Dr. Gaske posited the existence of a "psychological barrier" to investing in a public utility like Great Plains, where the allowed ROE goes below 10%.[91] The Department disputed the existence of any such barrier and noted that all but two of the companies in the Gaske Group had allowed ROEs of less than 10%. The Department also noted that this reference to a psychological barrier appears only in Dr. Gaske's testimony, without reference to any other source. Great Plains maintained that the 10% barrier was a "rule" for which utilities granted an ROE of less than 10% would be exceptions.[92]

71. Great Plains asserted that a recent survey of newly authorized ROEs showed that an ROE of greater than 10% was commonplace in the industry.[93] The survey shows the highest ROE was 12.0% and the lowest was approximately 9.6%. There is no evidence in the record to show that any of these companies are in any way comparable to Great Plains.[94] No psychological barrier has been shown to require the bottom of the ROE range be set at 10%.

72. The effect of Dr. Gaske's approach is to give undue weight to the two outlier companies, KeySpan and Atmos. As discussed above, KeySpan is not

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[88] Tr. Vol. 2, at 299-300.

[89] Company Ex. 8, Gaske Direct, JSG-2, Schedule 2, at 1.

[90] Tr. Vol. 2, at 217-218. Great Plains asserts that a subsequent asset sale by Keyspan brings that company within the earnings screen. Subsequent activity by a utility is not relevant to the analysis conducted, particularly where the proceeds of the asset sale constitute a further variable not reflected in that company's prior ROE figure. Further, Keyspan's overall difference in size is an independent reason for excluding it from the comparison group.

[91] Company Ex. 9, Gaske Reply, at 1

[92] Great Plains Reply Brief, at 14-15.

[93] Company Ex. 39.

[94] One listed company, South Jersey Gas Co., has a similar name to a company appearing in both comparison groups. Another listed company is MD Utilities, of which Great Plains is a division. Both of these companies are at the low end of the range of surveyed utilities. Company Ex. 39.

comparable to Great Plains and should not be considered in the comparison group. The results derived by Dr. Griffing's analysis accurately reflect the range of comparable companies and the averaging method used appropriately identifies the ROE to be established in this proceeding.

Risk

73. As discussed above, Dr. Griffing used the MDU bond rating as a proxy for Great Plains. Dr. Gaske strongly objected to the use of MDU's bond rating as insufficiently stating the risk borne by a hypothetical investor in the hypothetical stand-alone Great Plains. The risks identified by Dr. Gaske as higher than a normal gas transmission and distribution company are size, lack of diversity in customer base, and lack of weather normalization in rate design.[95] Regulatory risk, business risk, market risk, and financial risk were assessed as average.[96] In the main, these perceptions of higher risk were subjective perceptions, not quantified by a comparison to information from any other companies in the comparison group.[97] These risk assessments were cited as the support for concluding that Great Plains should have an ROE on its common equity of 11.0%.

74. The Department objected to the Company's use of risk as a basis for concluding a higher ROE is needed for Great Plains. Generally speaking, risk is an appropriate factor to consider in establishing Great Plains' ROE. Dr. Gaske identified the recent yields on A-rated public utility bonds as 6.3% and on Baa-rated public utility bonds as 6.4%.[98] Risk is already included in the bond rating, which is the initial starting point for the ROE calculation. The elements identified as comparative risk factors are already contained in the ratings for the comparison group companies. There is no basis for reintroducing risk as a stand-alone factor for determining ROE. To do so would overemphasize one factor in the calculation and distort the results obtained.

Flotation Cost Adjustment

75. The cost of raising new common equity capital is known as the flotation cost. To avoid dilution of existing capital, a flotation cost adjustment is applied to a company's common equity investment. In arriving at a flotation cost adjustment, Great Plains surveyed 34 natural gas transmission and distribution companies that issued common stock between 1992 and 2002. The average flotation cost of those new issues was calculated to be 4.77%. From that calculation, Great Plains concluded that 4.75% was an appropriate flotation cost adjustment.[99] That flotation cost was used in the DCF calculation used by Great Plains when determining the range of ROEs and RORs in the Gaske comparison group.[100]

[95] Company Ex. 8, Gaske Direct, at 28.
[96] Company Ex. 8, Gaske Direct, at 28-32.
[97] Transcript, Vol. 1, at 54-60.
[98] Company Ex. 8, Gaske Direct, at 10.
[99] Company Ex. 8, Gaske Direct, at 12.
[100] Company Ex. 8, Gaske Direct, JSG-2, Schedule 2, at 7.

76. The Department maintained that the survey of equity issuance costs used by Great Plains was outdated. The Department's calculation used actual equity issuance costs for MDU over a period including the four most recent equity issues. This period includes the February 2004 issue of $51 million in MDU common stock. The flotation cost for that single issuance was 4.2% of the Company's dividend yield.[101] The average flotation cost over the four issues was 4.32% of yield.[102]

77. The Department also objected to how the Company applied the adjustment factor, indicating that Great Plains should not have included the growth-rate component as well as the dividend-yield component in its adjustment method. The Department maintained that the flotation-cost factor should be applied only to the dividend-yield component, which compensates for the reduction in the base upon which a company earns, thereby restoring the effective ROE opportunity to that indicated by the DCF method.[103] Dr. Gaske acknowledged that only the dividend-yield component should have been adjusted.[104]

78. The Department's methodology in calculating Great Plains' cost of equity issuance is superior to that advanced by Great Plains. The average of costs actually incurred in equity issues is a better predictor than a survey of other companies' costs, more or less similar to Great Plains, reaching back to 1992. The benefit of a recent bond issue in reducing costs does not distort the resulting average.

Return on Earnings and Rate of Return

79. In his Surrebuttal Testimony, Dr. Griffing added three companies to his comparison group and recalculated the Company's ROE to be 9.72%. He added two of the companies to his comparison group after receiving updated data indicating they met his earnings screen of having 65% or more of their earnings from natural gas revenue. Based on the Company's Rebuttal filing, Dr. Griffing also adjusted his long-term debt cost up from 7.12% to agree with Great Plains' figure (8.52%). The ROE (9.72%) can be viewed as the sum of a new yield of 4.27%, a new growth figure of 5.26% and a flotation cost adjustment of 0.19% (unchanged).[105] The preponderance of the evidence supports the Department-sponsored ROE of 9.72% and the resultant ROR of 8.96%.

K. Corporate Overhead Allocation

80. Great Plains is operated by MDU as a division. In its cost accounting, MDU allocates some of its corporate overhead costs to Great Plains to reflect expenses incurred on behalf of that division. Great Plains described these costs as "known and measurable expenses."[106] These costs generally fall in the Administrative and General ("A&G") and Operations & Maintenance (O&M) expense categories. The Department

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[101] Company Ex. 8, Gaske Direct, at 13.
[102] Department Ex. 23, Griffing Direct, at 44.
[103] Department Ex. 24, Griffing Surrebuttal, at 13-15.
[104] Company Ex. 9, Gaske Rebuttal, at 12; Transcript, Vol. 1, at 47-48.
[105] Department Ex.24, Griffing Surrebuttal, at 7 and17 and MFG-S-4.
[106] Company Initial Brief, at 28 (citing Tr. Vol. 4, at 449, lines 14-17).

audited the Company's claimed expenses to assess the basis for the proposed test-year costs (projected 2005 costs) in this rate case. The Department reviewed Great Plains' historical data and budgeted data.[107]

81. The Department expressed concern that the actual 2003 income statement included expenses that the Commission expressly identified in the ***Merger Order*** as not recoverable from future ratepayers. The actual 2003 other O&M expenses were $404,552 higher than approved in ***2003 Rate Order***.[108] The $404,552 increase in actual 2003 other O&M expenses, over the level approved in the Company's last rate case, accounts for 30 percent of the Company's 2005 revenue requirement in this case. The Department focused its review on the other O&M costs, including corporate costs that were either directly assigned or allocated to Minnesota ratepayers.[109]

82. The Department asserted that Great Plains has not shown the reasonableness of its cost allocations to regulated ratepayers. Two aspects in allocating costs were identified as problems. The first was the need to reasonably allocate payroll and benefits costs associated with Great Plains' common (indirect) accounting and general administrative tasks between Great Plains' regulated and non-regulated businesses. The second was whether Great Plains' use of the "two-factor method" of allocating other corporate costs (from MDU or MD Utilities) to regulated ratepayers meets the allocation criteria established by the Commission.[110]

Regulated and Non-regulated Business Cost Allocation

83. Great Plains' Minnesota-regulated gas distribution business shares services with Great Plains' North Dakota gas distribution business, as well as the other regulated gas and electric distribution businesses of MDU's other operating division, MD Utilities. The two operating divisions, Great Plains and MD Utilities, also provide and share services with non-regulated sales and service activities such as appliance service and repair. The regulated gas and electric distribution businesses, as well as the non-regulated sales and services provided by MD Utilities and/or Great Plains, are referred to collectively as the Utility Division. Additionally, Great Plains and MD Utilities share MDU's corporate services with the other subsidiaries that are consolidated as business segments of MDU.[111]

Time Study for Cost Allocation

84. Due to concerns expressed in the 2003 rate proceeding, Great Plains conducted a time study for Great Plains employees who perform both regulated and non-regulated functions.[112] The purpose of the time study was to ensure that information regarding the expenses charged to regulated and non-regulated functions is

[107] Department Ex. 73, Lusti Direct, at 4.
[108] Department Ex. 73, Lusti Direct, DVL-19.
[109] Department Ex. 73, Lusti Direct, at 7.
[110] Department Ex. 43, Bender Direct, at 10-11, 17-20.
[111] Department Ex. 43, Bender Direct, at 3.
[112] Department Ex. 43, Bender Direct, at 8-9.

current and available for review,[113] thereby allowing the Commission to evaluate the reasonableness of the Company's proposed allocations.

85. Great Plains' time study allocated labor costs between Great Plains' regulated business and its unregulated service and repair (S&R) business based upon cost-causative factors, *i.e.*, the factor applied to each employee's payroll and related expenses is based on each employee's direct time as translated to an annual percentage.[114] Common time (*i.e.*, time in which an employee worked on a common activity for both S&R and Great Plains) was allocated in accordance with how an employee recorded his/her direct time in the time study.

86. The time study performed allocates the payroll and related expense of approximately 30 Great Plains employees, with approximately 20 of these employees allocating time to non-regulated functions.[115] As noted by Ms. Mulkern, "the employees whose payroll is allocated using a time study are generally clerical, engineering and supervisory employees. Other employees, such as servicemen, fill out time tickets and these employees were not a part of the study."[116] The employees recorded their time according to the following structure:

A.	Construction-related activities (other than actual construction or direct field supervision which should be charged directly to a blanket or specific work order) by the engineering and supervisory (ES) functions and the general and administrative (GA) functions.
B.	Service and Repair activities such as assisting customers with appliance feature demonstrations, appliance purchases, appliance accessories and Safe-N-Secure demonstrations and sales.
C.	Service and Repair activities generating invoices and establishing billing for preferred service, safe-n-secure and other S&R programs, processing warranty and appliance damage claims and similar paperwork.
D.	Utility Customer Service activities, including meter orders, billing related inquiries, collection activities, payment receipts, etc for the electric and gas utility functions.
E.	Utility miscellaneous accounting activities, including utility MAR invoicing of gas service lines, temporary electric services, utility damage billing, joint trench billing inventory chargeouts, account reconciliations, meter test billings or refunds, other utility billing, etc.
F.	Record straight time productive hours directly chargeable to a construction work order (blanket or specific) or to utility transmission or distribution operation/maintenance activities. DO NOT include overtime hours. This should include general employee meetings and safety meetings.
G.	Record nonproductive time (e.g. vacation, sick leave, holiday, etc.) [117]

[113] The Company also agreed to work with the Department in designing the scope and procedures to be followed in conducting the time study. Department Ex. 43, Bender Direct, at 7. It did not do so. *Id.* at 10. The failure of the time study to measure separately time spent on combined regulated/non-regulated tasks likely would have been remedied had that cooperation been forthcoming.
[114] Company Ex. 20, Mulkern Revised Rebuttal at page 9, lines 12-15; *see also* Company Ex. 5, Great Plains' Response to Information Request No. 112 ("Time Study").
[115] Company Ex. 20, Mulkern Revised Rebuttal, at 8.
[116] Company Ex. 20, Mulkern Revised Rebuttal, at 8.

[117] Company Initial Brief, at 65.

87. Categories B and C relate directly to time spent on unregulated S&R business activities. Categories A, D, E and F relate directly to time spent on Great Plains' regulated activities, with category G relating to "non-productive" time. Participants in the study were required to record their time every day for a month in the above categories, and their recordings were subsequently reviewed and annualized under the time study.[118]

88. The Department maintained that the time study was not designed to identify, and did not separately identify, the amount of time employees spent on tasks that included both regulated as well as non-regulated functions, also referred to as combined tasks.[119] The Department maintained that another category of time, time spent on combined tasks (referred to as "indirect time"), was not identified. Rather, the study identifies, in part, the productive time that employees spent on sales and clerical tasks directly identifiable as associated with the non-regulated service and repair business, called direct time.[120]

89. Great Plains' time study allocates payroll and benefits costs so that the total percentage of customer and clerical related costs allocated to its non-regulated S&R business reflects only the customer and clerical related activities directly assigned to the S&R business.[121] As a result, all costs associated with such tasks performed for the common benefit of regulated and non-regulated operations are, by default, included in the total percentage of customer and clerical related costs allocated to Great Plains' regulated ratepayers.[122]

90. Great Plains acknowledged that time spent on combined activities is not separately captured by the time study regardless of whether or not the employee performing the combined activity has direct time in the non-regulated business category.[123] Great Plains' billing tasks highlight the shortcomings of the Company's time study. Time spent on combined tasks where the amount of time associated with each operation (non-regulated and regulated) is not reasonably identifiable is precisely the type of activity that should have been measured. Doing so would have allowed identification of the percentage of payroll and benefits costs to be allocated between regulated and non-regulated operations for this type of combined task. The Company then could have allocated the associated costs "based upon an indirect cost-causative linkage to another cost category" of some kind (e.g., number of customers, revenues, other costs, etc.) in order to arrive at a reasonable allocation of such costs between regulated and non-regulated operations.[124] Great Plains' assignment of payroll and benefits costs to non-regulated customer service and clerical costs based on only the

[118] Company Ex. 20, Mulkern Revised Rebuttal, at 8.
[119] Tr. Vol. 1, at 150-151; 155-156; 172-175; Department Ex. 48, Bender Supp. Surrebuttal, at 4.
[120] Tr. Vol. 2 at 316-18.
[121] Department Ex. 45, Bender Direct, SB-10.
[122] Department Ex. 47, Bender Surrebuttal, at 2-3.
[123] Tr. Vol. 1 at 172-175.
[124] Department Ex. 43, Bender Direct, at 10-12.

percentage of time directly devoted to such non-regulated activities resulted in an unreasonably low allocation to non-regulated operations and an unreasonably high allocation to regulated operations.

91. The Department asserted that a great number of Great Plains' bills contain charges for its non-regulated service and repair (S&R) business. In 2004, the number of Minnesota customer bills that contained regulated gas utility charges totaled 323,182. The number of bills that contained non-regulated S&R charges equaled 55,199.[125]

92. Great Plains asserted that the lack of a separate measure for time spent on combined regulated/non-regulated tasks should not result in an adjustment of the proposed allocation. The Company asserted that any difference in time spent would have been statistically insignificant.[126] The Company did not demonstrate that the time, or costs, associated with combined regulated/non-regulated tasks are insignificant. Great Plains non-regulated operations are significant in comparison to its regulated distribution operations.[127]

93. While the absence of measurement in the time study renders precision impossible, significant employee time (combined or indirect time) is likely to have been spent on combined regulated/non-regulated bills. Great Plains' proposed allocation of employee costs will result in Minnesota ratepayers subsidizing non-regulated business activities of Great Plains. This subsidization will not result in just and reasonable rates.

94. The Department proposed an adjustment to Great Plains' allocation to account for non-regulated operations unaddressed by the time study. The Department applied the 17.8 percent general allocation factor to assign approximately 2.97 percent of time study participants' total payroll and benefits costs from regulated to non-regulated activities. This adjustment represents the non-regulated share of estimated common customer accounting and miscellaneous administrative costs. With the Department's adjustment, a total of about 6.63 percent of direct and indirect regional payroll and benefits costs is allocated to the non-regulated S&R activities of Great Plains.[128] This recommendation would ensure that at least a portion of Great Plains' unaccounted for combined regulated/unregulated costs is allocated to non-regulated operations.[129] The adjustment is approximately 6.4 percent ($28,223 divided by ($457,525-$16,677)) of the time study participants' customer and clerical related payroll and benefits costs.[130] This adjustment results in a more accurate allocation of costs between regulated and non-regulated business processes.

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125 Department Ex. 48, Bender Supp. Surrebuttal, at 6.
126 *See* Tr. Vol. 1, at 151..
127 Department Ex. 45 , Bender Direct, SB-11; Department Ex. 75, Lusti Surrebuttal, at 12-13.
128 Department Ex. 46, Bender Surrebuttal, at 2-3.
129 *Id*.
130 *See* Department Ex. 45, Bender Direct, SB-10.

Corporate Cost Allocation

95. Great Plains allocated costs from MDU and MD Utilities in the O&M category to reflect costs of operating the Company's regulated utility business that are actually incurred by those other entities. These costs include salaries (including bonuses), insurance, a GIS system, and information technology costs. As an initial matter, the Department compared the comparable costs, as projected by Great Plains in its prior rate case, with the actual amounts claimed in this rate case for the same year, 2003.

96. Great Plains' projected 2003 corporate costs in the last rate case were $861,120.[131] The Company's actual year 2003 corporate costs were $1,584,629, all of which was allocated or directly assigned from MD Utilities or MDU to the Minnesota operations of Great Plains. The actual 2003 corporate costs allocated or directly assigned to Great Plains-MN was 84 percent greater ($1,584,629 - $861,120 = $723,509) than projected in the last rate case.[132]

97. The Department asserted that the ***Merger Order*** created a cap (called the "merger cap") on corporate costs from the projected 2005 test year, and that the actual excess for 2003 over 1999 levels ($582,183) must be inflated to a 2005 level, and then deducted from 2005 operating expenses. Properly inflating the $582,183 excess by the CPI to a 2005 level results in a $609,579 excess of corporate costs that the Department argues is unreasonable to include in the current rate case test year.[133]

98. The Department recommended an adjustment to reduce test year A&G expenses by $149,945 to reflect the aggregation of costs improperly allocated to Great Plains from MDU or MD Utilities.[134]

99. The Commission has addressed cost allocation issues in the context of avoiding harm to ratepayers. In the ***1008 Docket***, the Commission has recently stated:

> One result of a more competitive energy industry is a rise in transactions between regulated utilities and their nonregulated affiliates engaged in related operations. Energy utility diversification into affiliated operations has the potential for benefiting utility ratepayers through shared costs and greater efficiencies. Diversification into affiliated operations also holds the possibility of harm to utility ratepayers.

[131] Department Ex. 73, Lusti Direct, DVL-8.
[132] Department Ex. 73, Lusti Direct, at 9-10.
[133] Department Ex. 73, Lusti Direct, at 11 (footnote 4); Department Initial Brief, at 30.
[134] Department Ex. 77, Lusti Supp. Surrebuttal, at page 22. The Department prepared an alternative proposal for the reduction of the Great Plains' A&G expenses in the amount of $471,601 in the event the Commission rejects the Department's separate allocation adjustments and proposed adjustment to incentive compensation, which are discussed later in this Report. Department Ex. 75, Lusti Surrebuttal, at page 7.

> A monopoly utility has a natural impetus to shift costs from the nonregulated to the regulated operation, where costs are covered in rates, or to not acknowledge benefits to the nonregulated entity from joint operations. If improper cost or benefit allocations do occur, the result is subsidization of the nonregulated affiliate by the regulated utility. The regulator's charge in the changing energy industry environment is to ensure fair, equitable sharing of burdens and benefits between regulated monopoly operations and affiliated nonregulated operations. The regulator must also ensure that energy utilities adopt systematic and comprehensive reporting methods to allow regulatory monitoring of cost and benefit allocations between regulated and nonregulated operations.[135]

100. The rationale of the ***2004 1008 Docket Order*** applies with even greater force where, as here, costs are allocated from a corporate entity with diverse, multi-state and international non-regulated business operations. Where a stand-alone company can show costs incurred by reference to its own costs, the post-merger Great Plains has been allocated costs from outside its own business operations. The allocation of these other costs raises the risk that Minnesota ratepayers are being charged for services benefiting other business structures outside of the Minnesota operations of the Great Plains division. By operation of Minn. Stat. § 216B.03 (2004), the burden is on Great Plains to show that its reporting methods do not subsidize non-regulated operations through the charges imposed on Minnesota ratepayers.

101. The Commission has established a methodology to be used in allocating such corporate costs to regulated utilities in rate setting. The Commission's approach requires that:

> 1. Tariffed rates shall be used to value tariffed services provided to the nonregulated activity.
>
> 2. Costs shall be directly assigned to either regulated or nonregulated activities whenever possible.
>
> 3. Costs which cannot be directly assigned are common costs which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.
>
> 4. When neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed

[135] ***ITMO an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities***, G,E-999/CI-90-1008 (Order Setting Filing Requirements issued September 28, 2004)("***2004 1008 Docket Order***")(generally, "***1008 Docket***").

to regulated and nonregulated activities, excluding the cost of fuel, gas, purchased power, and the cost of goods sold. [136]

102. The Commission required utilities to use the "preferred" approach, unless the utility could demonstrate that (1) its non-regulated activities are insignificant; (2) the cost allocation principles used produce results similar to the Commission's preferred allocation principles; or (3) the public interest is better served by another method.[137] Great Plains maintains that its two-factor allocation method produces results similar to the Commission's preferred allocation principles and that the public interest is served by employing the two-factor method. Great Plains also asserts that its time study appropriately allocates payroll expense between S&R and Great Plains.[138]

103. Treating Great Plains' non-regulated activities and Great Plains-MN regulated costs as accounting for 100%, the properly calculated non-regulated activities account for 17.8% of costs.[139] That level is significant. The Department has correctly calculated 17.8% as the general allocator for Great Plains' non-regulated activities.

104. A different calculation is made for allocating corporate costs across MDU's business for inclusion in the rates paid by Minnesota gas customers. The Company asserted that the results of its two-factor method resulted in an allocation of 10.5 percent of these corporate costs to Great Plains, compared to 11.8 percent using the four-factor formula of the ***1008 Docket***. Great Plains' two-factor method is based on employees and physical plant, rather than operating expense as set out in the four-factor formula established in the ***1008 Docket***.[140] Great Plains justified this approach as reasonable, stating, "[t]hese two components are common to all companies within MDU Resources and given the diverse nature of MDU Resources, this formula provides a fair and cost effective allocation method serving the interests of its customers and the public."[141] The reasoning of this approach was described as, "MDU Resources has elected to use an alternative two-factor formula based on the logic that employees (the company's intellectual capital) and the physical plant are the primary assets being managed."[142] Based on the two-factor method, the Company proposed allocating 10.5 percent of MDU Resources' general corporate costs to the gas distribution segment, which includes Great Plains.[143]

105. The Department asserted that Great Plains incorrectly calculated the four-factor formula in arriving at its conclusion that 11.8 percent would have been the

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[136] ***1008 Docket***, (Order Setting Filing Requirements issued September 28, 1994).
[137] *See e.g.,* ***In the Matter of a Petition by Greater Minnesota Gas, Inc. for Authority to Establish Natural Gas Rates in Minnesota***, Order Accepting Filing Effective When Complete, Docket No. G-022/GR-04-667 (June 18, 2004).
[138] Company Initial Brief, at 57.
[139] Department Ex. 45, Bender Direct, SB-11. and Department 75, Lusti Surrebuttal, at 12-13..
[140].Company Ex. 10, Keller Direct, at 9.
[141] Company Ex. 10, Keller Direct, at 9.
[142] Company Ex. 10, Keller Direct, at 9.
[143] *See* Company Ex. 10, Keller Direct, CAK-1.

appropriate calculation.[144] Great Plains maintains that it only excluded the costs of purchased goods sold from its 11.8 percent calculation and that this is consistent with the ***1008 Docket*** allocation methodology. The Department contends that "cost of goods sold" is limited to the costs of items purchased for resale, "not some broader definition of cost of goods sold."[145] The Department's analysis of Great Plains' calculation of an 11.8% allocation under the ***1008 Docket*** methodology concluded that Great Plains unreasonably "excludes costs incurred in performing non-regulated business activities, such as labor expense."[146]

106. The Commission's description of excluded costs shows that labor is not to be excluded. It is not a "purchased cost of goods sold." Specifically, in the ***1008 Docket***, CenterPoint Energy Minnegasco (CenterPoint) requested that the Commission clarify that the "costs of goods sold" to be excluded from the calculation of the general allocation factors is limited to "items purchased for resale and not some broader definition of 'costs of goods sold.'"[147]

107. The Commission clarified the Order as requested by CenterPoint and confirmed that pass through costs are the only costs to be excluded from the Commission's general allocation calculation:

> The clarification does not alter the Commission's basic intent, which is to exclude from the general allocator costs which are passed through to customers. Such costs include the cost of purchased goods sold.[2] The benefit of the clarification is that it promotes uniform application of the exclusion of cost of goods sold among all utilities.
>
> [2] The cost of *purchased* goods, as contrasted with the cost of *manufactured* goods, are passed through to customers and, hence, should be excluded from the general allocator.[148]

108. Great Plains asserts that the businesses operating under the MDU Resources' umbrella incur other costs in providing services and sales to their customers. Rather than purchasing appliances for resale, however, these businesses purchase goods for resale from various manufacturing entities, as well as incur various internal costs such as direct labor costs.[149] MDU's diverse "business lines include construction materials and aggregate mining, natural gas and oil production, pipeline and energy services, independent power production and utility services, in addition to

[144] Department Ex. 47, Bender Surrebuttal, at 6.
[145] Bender Surrebuttal at page 6, lines 3-7.
[146] Bender Surrebuttal at page 8, lines 8-9.
[147] ***Petition for Clarification Regarding Cost Allocation***, Docket No. G,E-999/CI-90-1008, October 18, 1994 (emphasis in original).
[148] ***1008 Docket***, Docket No. G, E-999/CI-90-1008, (Order Clarifying Commission Order Dated September 18, 1994, issued March 7, 1995)(***1008 Docket Clarifying Order***)(emphasis in original).
[149] Company Ex. 12, Renner Rebuttal, at 11-12.

the regulated electric and natural gas distribution utility and non regulated utility operations of its utility division, Montana-Dakota/Great Plains."[150]

109. Great Plains maintains that its treatment of costs in arriving at the cost of goods sold is a "distinction without a difference."[151] But Great Plains has not explained how the costs incurred in its diverse business operations to produce finished products equates to the purchase of manufactured goods for resale within the meaning of the ***1008 Docket Clarifying Order***.[152] The business processes inherent in the processing of raw materials require a higher allocation of corporate costs than retailing manufactured goods. There is a clear difference between the business operations required for resale of manufactured goods and the business operations engaged in by MDU's diverse subsidiaries. The proper calculation of the corporate allocation factor, using the ***1008 Docket*** methodology, will result in a significantly smaller allocation of costs to Great Plains.

110. The Department demonstrated that the Commission's preferred method would result in an MDU Resources cost allocation factor of about 3.2 percent.[153] The Company's considerably higher cost allocation factor would result in about $215,596 more being charged to regulated operations in the test year than would the Commission's method.[154]

111. The Company asserts that it is only seeking to allocate "Great Plains' actual costs of providing service to its Minnesota customers."[155] Great Plains indicates that its net income in 2004 results in a negative return on equity.[156] But Great Plains is seeking to charge Minnesota ratepayers for costs actually incurred by MDU and MD Utilities. The extent to which MDU and MD Utilities are charging costs to Great Plains affects Great Plains' net income, and thereby the Company's return on equity. The issue before the Commission is whether those allocated costs are reasonable.

112. The use of the two-factor allocation has not been shown to produce similar results to those of the four-factor method, when properly applied. No public interest has been shown to be better served by using the two-factor method.

113. Great Plains has not shown the reasonableness of its cost allocations to regulated ratepayers. Specifically, it failed to show the reasonableness of its proposed cost allocations in two important respects: 1) it made no credible showing that payroll and benefits costs associated with Great Plains' common (indirect) accounting and general administrative tasks are reasonably allocated between Great Plains' regulated and non-regulated businesses; and 2) it made no credible showing that its "two-factor

[150] Company Ex. 12, Renner Rebuttal, at 13.
[151] Company Initial Brief, at 62.
[152] *See* Company Ex. 12, Renner Rebuttal, at 13 (identifying purchasing raw materials, concrete, rebar, poles, and wires and incurring direct labor costs to produce finished products).
[153] See Ms. Bender's Direct and Surrebuttal for analysis and calculation of the 3.2 percent estimate. Department Ex. 47, Bender Surrebuttal, at 8-10.
[154] Department Ex. 47, Bender Surrebuttal, at 12 ($310,104 - $94,508 = $215,596).
[155] Company Ex. 7, Imsdahl Rebuttal, at 3.
[156] *Id*. at 2.

method" of allocating other corporate costs to regulated ratepayers satisfied the Commission's allocation criteria.[157]

Cost Allocation Adjustments

114. The Department noted that Commission could disregard the time study entirely, and allocate all of Great Plains' payroll-related costs based solely on the generic cost allocation factor of 17.8 percent. The Department proposed that the 17.8 percent general allocator be used only toward the payroll-related costs recorded by Great Plains as regulated customer accounting and miscellaneous A&G costs.[158] That is, the Department applies the 17.8 percent factor to allocate approximately 2.97 percent of time study participants' total payroll and benefits costs from regulated to non-regulated to represent the non-regulated share of estimated common customer accounting and miscellaneous administrative costs.

115. With the Department's adjustment, a total of about 6.63 percent of direct and indirect regional payroll and benefits costs is allocated to the non-regulated service and repair activities.[159] This recommendation would ensure that a portion of combined regulated/unregulated costs are allocated to non-regulated operations.[160] The Department's recommendation leaves intact Great Plains' allocation to the extent it was based on time and costs directly identified as non-regulated, but adds an allocation component to address combined (indirect) time and costs.[161]

116. This adjustment would result in a reduction of Great Plains' projected test year Customer Accounting expenses by $45,734 and A&G costs by $3,300 to reflect the allocation of an additional $49,034 of payroll and benefits expenses to Great Plains' non-regulated business.[162]

Incentive Compensation

117. Great Plains has structured its total compensation as a combination of a base salary and compensation based on incentives. Through the Revised Direct Testimony of Ms. Rita A. Mulkern and the Rebuttal Testimony of Mr. Richard D. Spratt, Great Plains proposed recovery of labor expenses in the amount of $225,511 associated with five incentive compensation plans.

118. The Department objected to recovery of executive incentive compensation over a certain level. The Company's initial testimony included only one reference to bonuses.[163] Great Plains' witness Mulkern states that "the projected labor costs are based on the labor amounts budgeted for 2004, adjusted to reflect a three year average amount for the bonuses and amounts to 6.82 percent increase for 2004." There is no

[157] Department Ex. 43, Bender Direct, at 10-11, 17-20; Department Initial Brief, at 59-60.
[158] Department Ex. 46, Bender Surrebuttal, at 2; Department Ex. 43, Bender Direct, at 11.
[159] Department Ex. 46, Bender Surrebuttal, at 2-3.
[160] *Id.*
[161] *Id.*
[162] Department Ex. 48, Bender Supp. Surrebuttal, at 8..
[163] Company Ex. 18, Mulkern Direct, at 10.

other direct testimony regarding incentive pay.[164] The Department noted that the Company's Executive Incentive Compensation Plan award is based on two items: earnings per share (EPS) and return on invested capital (ROIC).[165]

119. Great Plains asserted that its incentive compensation plans are offered to all employees in an effort to remain competitive within the industry and to focus employee efforts on achieving business objectives, including controlling or reducing costs, achieving greater efficiency and implementing programs that benefit customers and support customer service.[166] Great Plains maintained that the incentive compensation plans are similar to plans sponsored by other utilities and reflect current market conditions conservatively.[167]

120. The Department's original disallowance proposal was $98,051.[168] The Department proposed that expenses be allowed for the BETA and Mid-Management Plans and make one other change, resulting in a proposed adjustment to reduce test year expense associated with incentive compensation by $62,059.[169]

121. Great Plains seeks to distinguish its situation from that in a prior Commission Order on this issue, which states:

> The Commission continues to believe, for the reasons set forth in the original Order, that the officers' and executives' plans allow too high a proportion of these employees' total wages to come from incentive compensation. (These plans provide for incentive payments of up to 40% of base pay.) The Commission will limit recoverable incentive payments to 15% of an individual's base salary.[170]

122. Great Plains maintains its overall compensation levels are not above market. The Montana-Dakota and Great Plains base pay philosophy was described as "more conservative" and striving "to pay at market average."[171] Great Plains also noted that there is no evidence that management has recently declined to actually pay incentive compensation.[172]

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[164] Department Ex. 73, Lusti Direct, at 23.
[165] Department Ex. 73, Lusti Direct, at 25.
[166] Company Ex. 17, Spratt Rebuttal, at 3-5.
[167] Company Ex. 17, Spratt Rebuttal, at 3-8, and RDS-1. Mr. Spratt testified that "[d]ata from the 2004 Watson Wyatt Survey Series indicated a strong trend continues to provide employees in the utility industry the opportunity for bonuses and other incentives. Approximately 80 percent of hourly employees, 80 percent of salaried employees, and 90 percent of management employees are eligible for bonuses in our industry . . . The Montana-Dakota and Great Plains base pay philosophy is more conservative than many organizations in the Watson Wyatt surveys. The utility division strives to pay at market average." Company Ex. 17, Spratt Rebuttal, at 8..
[168] Department Ex. 75, Lusti Surrebuttal, DVL-S-9.
[169] Department Ex. 75, Lusti Surrebuttal, at 22, DVL-S-9.
[170] ***In the Matter of the Petition of Northern States Power Gas Utility for Authority to Change Its Schedule of Gas Rates for Retail Customers Within the State of Minnesota***, Docket No. G-002/GR-92-1186, at 7 (Order After Reconsideration issued December 30, 1993).
[171] Company Ex. 17, Spratt Rebuttal, at 8.
[172] Company Initial Brief, at 46.

123. Great Plains has not shown that its incentive compensation plan is significantly based upon factors that are unrelated to earnings and stock price. Such incentive compensation is properly paid out of earnings, not by ratepayers. To the extent that other factors influence that compensation, they are appropriately included in the Department's proposal. The Department has shown that its proposal (as amended) regarding incentive compensation is reasonable and consistent with prior Commission orders.

124. Great Plains asserted that the Department double counted bonuses and excluded those costs twice in this calculation.[173] The ALJ accepts the calculation of the Department on this issue and concludes that those costs were not excluded twice in its calculations.[174] Great Plains' test year expense associated with incentive compensation is appropriately reduced by $62,059.

<u>Insurance Expense</u>

125. One of the areas where the Department and Great Plains are in dispute over the appropriate level of costs is insurance. Great Plains maintains that the scope and type of the insurance coverage it now maintains is "different" than the coverage it maintained prior to the merger and therefore the cost of insurance is not "comparable" within the plain meaning of the Merger Order.[175]

126. Great Plains explained its position on insurance as follows:

> Great Plains has been able to utilize MDU Resources' expertise and support to provide cost savings in the insurance area. The primary area that has experienced efficiencies and lower overall costs for Great Plains' customers is in the negotiating of lower rates as part of the MDU Resources companies than would be available to Great Plains on a stand-alone basis. Underwriting rules require that a larger percentage of fixed cost be embedded in a smaller program than the percentage that would be inherent in a larger program like that of MDU Resources, resulting in a significant savings to Great Plains. Also, the breadth of coverage and limits in the MDU Resources program was considerably greater than what Great Plains may have achieved on its own. The estimated savings in insurance expense for Great Plains are:

Test Year 2003	$572,724
Actual Year 2003	505,947
Test Year 2005	515,354[176]

[173] Company Ex. 14, Morehouse Rebuttal, at 15.
[174] Department Ex. 75, Lusti Surrebuttal, at 5.
[175] Tr. Vol. 4, at 463-464.
[176] Company Ex. 5, Great Plains' Response to Information Request No. 158.

127. The Department recognizes that the Company has no duty in the abstract to demonstrate merger savings. The discussion over savings arises from the Department's position that Company is limited to amounts allowed as a condition of the merger, unless those amounts are individually demonstrated to be reasonable or the cost is a "new" cost of a type not previously incurred.

128. The insurance obtained by MDU and allocated to Great Plains is described as a "corporate property and liability program" that has "higher deductibles and substantially higher limits than the expiring Great Plains program, coupled with correspondingly lower rates."[177] Changes in the insurance market were described as resulting in "an increase in insurance expense of over 100 percent since 1999 [for MDU]."[178]

129. Great Plains has demonstrated that insurance is not sufficiently standard so that a direct application of an inflation-adjusted cost is an appropriate means of determining allowable cost. The Department's recommended adjustment to reduce test year Administrative and General ("A&G") expenses by $149,945 must itself be reduced for the insurance expense properly allocated to Great Plains from MDU and/or MD Utilities.[179]

GIS Expense

130. MD Utilities implemented a Geographic Information System ("GIS") to meet the property management needs of the utilities in that division of MDU. Great Plains has proposed recovery of an allocated portion of the GIS. Mr. Morehouse explained that the utility operating environment has changed since 1999, resulting in increased costs for Great Plains related to the GIS, which cannot be legitimately attributed to the merger.[180] Mr. Morehouse noted that MD Utilities installed GIS beginning in 2001 due to new operating requirements and confirmed that neither Great Plains nor MD Utilities had such a system in 1999.[181] As noted by Mr. Morehouse, "advances in technology and today's operating environment dictate that such cost be incurred independent of the Great Plains and MDU Resources merger."[182]

131. Great Plains asserted that it achieved cost savings of $156,096 (for two full-time salaries) and capital investment totaling $700,348 through sharing the GIS expense. MDU allocated $5,386 in salaries and $246,404 in capital costs to Great Plains. The Department maintained that the savings figure was unsupported, since those figures would require Great Plains to incur the same level of expenses for GIS as for all of MDU. No objection was raised to the allocations for salary and capital cost. the Department recommends at this time that the Commission credit the Company by

[177] Company Ex. 14, Morehouse Revised Rebuttal, KFM-4.
[178] *Id*.
[179] Department Ex. Lusti Surrebuttal at page 22. The amount for the Department's proposed disallowance was not found itemized in the record.
[180] Company Ex. 19, Morehouse Revised Rebuttal, at 18.
[181] Company Ex. 19, Morehouse Revised Rebuttal, at 18.
[182] Company Ex. 19, Morehouse Revised Rebuttal, at 18-19.

allowing it the $5,386 allocated expense, and a return on the $246,404 allocated investment. This results in an increase in the rate base by $246,404 and increase of O&M expense by $5,386.[183] The ALJ agrees that Great Plains O&M should include $5,386 for allocated GIS salary expense and the rate base should include $246,404 for the allocated GIS investment.

132. Great Plains asserts that the insurance and GIS costs demonstrate that the Department's "corporate costs" adjustment is fatally flawed; that the Department neither considered whether increased corporate expenses "resulted from" the merger or are, in fact, "comparable" to 1999 costs.[184] These two expenses have been shown to be allowable independent of the baseline of costs to be established under the ***Merger Order***. These two expenses are independent of that baseline, not simply "known and measurable costs" akin to the remainder of the corporate cost allocation.

133. Great Plains also objected to the Department's position on the Company's claimed costs for (1) the installation of a new customer billing system in late 1999 to address Y2K issues as well as be responsive to the needs of Great Plains' customers;[185] and (2) increased telephone and computer connectivity.[186] All of these costs should have already been included in Great Plains' rate base as established in the ***2003 Rate Order***.[187] No separate showing has been made that those expenses are different from the baseline costs established in the prior proceeding.

L. Bad Debt Expense (undisputed)

134. The Department recommended a reduction in the Company's claimed bad debt expense of $15,239 based on a five-year average of write-offs to revenue using actual 2004 revenues, rather than projected 2004 revenues.[188] Great Plains agreed with the Department's recommendation, resulting in a reduction of test year expense of $15,239.

M. Advertising (undisputed)

135. Great Plains proposed to recover $6,191 in advertising expenses related to safety and informational advertisement in test year expenses.[189] The Department evaluated Great Plains' advertising expenses by applying the criteria set forth in Minn. Stat. § 216B.16, subd. 8, and concluded that all but $206 of the total advertising costs meets the stated criteria.[190] Great Plains agreed with the Department's determination

[183] Department Initial Brief, at 47.
[184] Company Initial Brief, at 37.
[185] Company Ex. 19, Morehouse Revised Rebuttal at 19.
[186] Company Ex. 19, Morehouse Revised Rebuttal at 20.
[187] Additionally, if the "computer connectivity" costs are related to the integration of the computing systems of Great Plains and MDU, then it is a cost "resulting from the merger" within the meaning of the ***Merger Order***, and thereby not an allowable cost.
[188] Department Ex. 75, Lusti Surrebuttal, at 17-18.
[189] Company Ex. No. 2, Schedule C-2, at 16 and Schedule C-7.
[190] Department Ex. No. 65, Minder Direct, Vol. 1, at 33.

that $206 in advertising expense should be excluded from the test year expense, reflecting a reasonable test year expense of $5,985.

N. Late Payment Fees (undisputed)

136. The Department's recommended that the test year level of late payment fees be based on the five-year (2000 – 2004) average of late payment revenue as a percentage of the sales and transportation revenue of the same period. The resulting 0.15 percent ratio is then applied to the Department's recommended test year sales and transportation revenue.[191] Great Plains agreed that this adjustment was appropriate. This calculation results in an adjustment to increase the test-year late payment fees by $53,762.[192]

O. Other Operating Revenue (undisputed)

137. The Company noted that its 2005 test year "Other Operating Revenue" was $204,039 based upon actual 2003 "other" revenue. The Department recommended using 2004 actual data ($209,800), which subsequently became available.[193] Great Plains agreed that the Department's proposal to use 2004 actual data to determine other operating revenue is appropriate, resulting in an increase in operating revenue by $5,761.

P. Rate Case Expenses

138. Great Plains estimated rate case expenses for this proceeding in the amount of $308,450. The Company's estimate included costs associated with (1) rate of return consulting fees, (2) outside legal fees, (3) state agency fees, (4) Great Plains' staff travel, and (5) administrative costs.[194] The Department did not challenge the Company's proposal to recover $308,450 of the rate case costs related to this proceeding, concluding that the Company's estimate is reasonable. Great Plains requests that its estimate be accepted.[195]

Rate Case Expense Allocation

139. While the overall amount for this rate matter is not in dispute, the Department recommended that 17.8% of rate case expense be allocated to non-regulated activities based on the Direct Testimony of Ms. Sundra Bender, and that the allowable amount reflect a five-year amortization of the rate case expense.

140. Great Plains maintains that the Department's proposal to allocate 17.8% of the rate case expense to Great Plains' unregulated S&R business is unreasonable. The Company claimed that its S&R business represents only 4 percent of total revenue

[191] Department Ex. 73, Lusti Direct , DVL-20.
[192] Department Ex. 75, Lusti Surrebuttal, at 19.
[193] *See* Department Ex. 73, Lusti Direct, at 20-21.
[194] *See* Company Exhibit No. 2, Revised Petition at Schedule C-2, page 18; Company Ex. 18, Mulkern Revised Direct at page 13.
[195] Department Ex. 73, Lusti Direct, at 12.

of the Company and simply cannot support an allocation of 17.8 percent of rate case expenses to Great Plains' unregulated activities.[196] Great Plains points out that the Commission has found that allocation of rate case expense to non-utility activities is only appropriate where the allocation accurately reflects the amount of additional review the Department undertook examining the unregulated activities.[197] Great Plains maintains that the Department's use of a general allocator is wholly unrelated to the costs incurred by the Company.[198]

141. The Commission approved similar allocations (reducing the allowable rate case expense) in a number of recent utility rate cases.[199] The Commission approved the Department's proposed (and settlement position) in CenterPoint Energy's rate case (Docket No. G008/GR-04-901). The Commission also recently approved the Department's proposed (and settlement position) in the Northern States Power Company rate case (Docket No. G002/GR-04-1511).[200] Great Plains' non-regulated operations are significant. Non-regulated revenues represent approximately 17.9 percent of Great Plains' total revenues (distribution service revenues plus non-regulated revenues).[201] Great Plains relies on a faulty calculation in asserting incorrectly that its non-regulated operations are insignificant. The Company improperly inflates the total revenues against which it compares those of its non-regulated operations by including revenues related to sales of the natural gas commodity. The revenues and costs associated with the natural gas commodity itself is not an issue for Commission decision in this rate case.[202] To eliminate non-regulated costs from regulated rates, the Commission's ***1008 Docket*** general cost allocation methodology specifically excludes "pass through costs."[203] Commodity costs (and revenues) are pass through costs that are properly excluded from a utility's cost allocation with respect to non-regulated operations.

142. A number of the controversial issues, requiring significant time and effort to resolve, arise directly from the allocations that Great Plains made between regulated and non-regulated business activities. The reduction proposed by the Department,

[196] *See generally,* Company Ex. 19, Mulkern Revised Rebuttal, at pages 2-3.

[197] *In the Matter of the Application of Minnesota Power for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota,* Docket No.: E-015/GR-94-001, Findings Of Fact, Conclusions Of Law, And Order at page 31 (November 22, 1994) ("[i]t is appropriate that rate case expenses be allocated to the non-utility activities when those activities require additional review to assure that the rate proposals are properly based on the costs of providing utility service.").

[198] Department Ex. 43, Bender Direct, at 20.

[199] Examples are: Northern States Power Company's last completed rate case (Docket No. G002/GR-97-1606), in CenterPoint Energy's last completed rate case (Docket No. G008/GR-95-700) and in Minnesota Power's last rate case (Docket No. E015/GR-94-001).

[200] *See* Department Ex. 73, Lusti Direct, at 13.

[201] Department Ex.75, Lusti Surrebuttal, at 12..

[202] Commodity-associated costs (and revenues) are passed automatically to ratepayers through the monthly adjustment to rates called the Purchased Gas Adjustment (PGA), together with a year-end true-up of actual purchased gas expenses. Minn. Stat. § 216B.16, subd. 7 (2004).

[203] Department Ex. 47, Bender Surrebuttal, at 4; Department Initial Brief, at 70.

resulting in an allowable rate case expense of $253,546, is reasonable and should be made to Great Plains' allowed rate case expense.[204]

Rate Case Expense Amortization Period

143. The Department proposed a five-year amortization period for the allowable rate case expenses based largely on the average period between rate cases.[205] Great Plains pointed out that the periods used include the 18 years that elapsed between Great Plains' rate cases in 1985 and 2002. That period is not representative of current conditions, particularly in light of Great Plains' very recent history. Excluding the 18-year period from the process, an average of 2-3 years passes between Great Plains' rate cases. A three-year amortization period is more representative of current conditions and is appropriate for the rate case expenses in this matter.

Prior Rate Case Expenses

144. Great Plains included the unamortized amount of the costs of the prior rate case (authorized by the Commission) as an O&M expense in the present case. Great Plains maintains that this expense is known and measurable for 2005. Great Plains argues that these expenses: (1) are approved costs related to the Department and Commission's regulatory oversight functions; (2) were approved for amortization over a three-year period commencing in 2004; and (3) would be, if disallowed at this time, fundamentally unfair and would result in a hardship if Great Plains was not able to recover these known costs.[206]

145. The Department objected to Great Plains including costs from outside its proposed rate case test year period to determine ongoing rates. Under normal rate making policy, a utility is not entitled to recover costs outside of its proposed rate case test year period. The test year ensures reasonable rates by matching investment, sales and expenses of a specific period.[207] Just as the test year concept protects a utility from having to include past out of period revenues in a rate case, it is not allowed to include past out of period costs. Rates must be prospectively applied.[208] There is no basis for including the unrecovered prior rate case expense in ongoing rates.

146. Great Plains cited a prior Commission ruling for the proposition that a natural gas company has been authorized to recover rate case expenses from a previous rate case.[209] In that matter, the Commission authorized Minnegasco (now CenterPoint Energy) "to offset the refund of interim revenues by $325,000, representing rate case expenses that have not been recovered from Minnegasco's and Midwest's

[204] Department Ex. 73, Lusti Direct, DVL-14.
[205] Department Ex. 73, Lusti Direct, DVL-14.
[206] Company Ex. 20, Mulkern Revised Rebuttal at 3-4.
[207] Department Ex. 75, Lusti Surrebuttal, at 14.
[208] *See* Minn. Stat. § 268.23, subd. 1 (2004).
[209] ***In the Matter of the Application of Minnegasco, a Division of Arkla, Inc., for Authority to Increase Its Rates for Natural Gas Service in Minnesota****,* Docket No. G-008/GR-93-1090, Findings of Fact, Conclusions of Law, and Order at 27 (October 24, 1994).

1992 rate cases."[210] The Commission did not build those prior expenses into rates. Rather, the Commission allowed an offset of overpaid revenues, essentially reducing the refund required of the utility for overcollecting on its interim rate. Great Plains is at liberty to request similar treatment by the Commission, assuming that an overpayment is found and a refund ordered.

Adjusted Prior Rate Case Expenses

147. In addition to the unamortized approved rate case expense from the prior rate case, Great Plains claimed an additional by $139,175.[211] Great Plains maintained that it had underestimated the costs incurred in undertaking a rate case in the State of Minnesota. The Department objected to this expense as unsupported and improper for inclusion in the test year calculation. The same analysis for the approved prior rate case expenses applies to this proposed adjustment. These expenses are not recoverable in rates.

Q. Revenue Deficiency

148. The ALJ agrees with the Department's calculation (see Finding 39, *supra*) regarding Great Plains' revenue deficiency, except that adjustments are needed to decrease the Company's operating income (which will increase its Income Deficiency) for insurance, GIS expenses, and amortization of the current rate case expenses consistent with the previous findings. No specific dollar amounts are recommended for these adjustments, as the ALJ is unable to isolate the particular figures from the record. In general, as reflected in the Conclusions in this Report, the ALJ estimates the revenue deficiency to be approximately $400,000, or a 1.2% increase in revenue.[212]

R. Conservation and Rate Design

Conservation

149. In accordance with Minnesota Statutes § 216B.241, Great Plains' 2003-2004 Conservation Improvement Plan ("CIP") was filed with the Department on June 3, 2002 in Docket No. G004/CIP-02-869. The Department issued a decision approving the 2003-2004 CIP on October 11, 2002. In the present case, both the Department and Great Plains agree that the 2003-2004 CIP plan as approved by Department in Docket No. G004/CIP-02-869 satisfies Minnesota Statutes § 216B.16.

150. In the ***2003 Rate Order***, the Commission approved the inclusion of $146,000 in CIP expenses in the test year.[213] The Commission also approved calculating the Company's Conservation Cost Recovery Charge (CCRC) by dividing the

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[210] *Id.*
[211] Company Ex. 20, Mulkern Revised Rebuttal at 4.
[212] *See also* Finding 211, *infra*.
[213] *In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-004/GR-02-1682, Order Accepting and Adopting Settlement at page 7 (October 9, 2003).

Commission-approved test year CIP expenses by the Commission-approved test year throughput.[214] The CCRC placed into base rates the CIP test year expenses.

151. Great Plains proposed to include $141,177 of CIP expenses in the test year.[215] The Department agreed with the Company's proposal and requested that the Commission approve Great Plains' proposed test year CIP expenses.[216] The Department and the Company agree that a revised carrying charge equal to the overall rate of return approved for the Company in the present case should be adopted.[217]

152. In the ***2003 Rate Order***, the Commission directed the parties to "discuss the advantages and disadvantages of two alternative methods of recovering Conservation Improvement Program costs: on the basis of dekatherms and on the basis of an equal percentage of operating revenues or margins" in the next rate case.[218] In the present case, the Company proposed allocating CIP costs on the basis of revenue generated by the Company's customer classes. The Company asserted that four advantages are derived from the Great Plains proposal: (1) a better match between cost recovery and cost causation; (2) a better match of cost recovery to the customer classes ultimately benefiting from the CIP; (3) minimization of inter-class subsidization by providing a proper match between cost causation and cost allocation; and (4) addressing the competitive challenges posed by interruptible transportation service customers on flexible rate contracts.[219]

153. The Department relied on the Commission's established precedent regarding allocation of CIP expenses. Specifically, in five recent gas rate cases, the Commission determined that the reasonable way to allocate CIP expenses was based on a volumetric method (i.e., Commission approved test year CIP expenses divided by Commission approved test year sales).[220] In addition, the Commission approved CenterPoint Energy's and NSP's proposed volumetric allocation of CIP expenses in

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[214] In its Order Accepting Compliance Filing with Modifications and Requiring Further Filings issued on January 16, 2004 in Docket No. G004/GR-02-1682, the Commission approved a CCRC of $0.0270/dekatherm for all customer classes. *In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-004/GR-02-1682, Order Accepting Compliance Filing with Modifications and Requiring Further Filings at page 5 (January 16, 2004). In its Order Approving CIP Tracker Account, Revised CCRA Factor, and Financial Incentive; Granting Variance; and Requiring Compliance Filing issued on January 16, 2004 in Docket No. G004/M-03-1009 and G004/M-03-1023, the Commission approved the Company's current CCRA of ($0.0042) per dekatherm.

[215] Department Ex.65, Minder Direct, Vol. 1, BJM-4.

[216] Department Ex.65, Minder Direct, Vol. 1, at 9.

[217] Department Ex.65, Minder Direct, Vol. 1, at 8.

[218] ***In the Matter of a Petition by Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota****,* Docket No. G-004/GR-02-1682, Order Accepting and Adopting Settlement at page 8 (October 9, 2003).

[219] Company Ex. 4, Aberle Supp. Direct, at 2.

[220] These five gas rate cases involved Interstate Power and Light Company; CenterPoint Energy Minnegasco (CenterPoint Energy); Northern States Power Company d/b/a Xcel Energy (NSP); UtiliCorp United, Inc.; and Great Plains (Docket Nos. G001/GR-95-406, G008/GR-95-700, G002/GR-97-1606, G007,011/GR-00-951, and G004/GR-02-1682, respectively).

Docket Nos. G008/GR-04-901 and G002/GR-04-1511, respectively, because the proposed allocation is consistent with Commission precedent. All Minnesota regulated gas utilities currently use the volumetric method to allocate CIP expenses.[221]

154. Based on this precedent, the Department advocates allocation of CIP expenses based upon the principle of cost causation (i.e., those customers who cause the cost to occur should pay for such costs). The Department recommended allocation of CIP costs is to allocate these costs among the rate classes on a volumetric basis (i.e., a per Mcf or dekatherm charge) as a reasonable means of reflecting this principle. Under this approach, customers consuming greater volumes of natural gas pay a greater share of CIP costs, no matter which rate class they are in.[222]

155. The Department objected to Great Plains' proposed CCRC for the firm customer classes because that approach would result in more CIP expenses being recovered from firm customer classes compared to the currently approved CCRC. By contrast, Great Plains' proposed CCRCs for the interruptible customer classes would result in less CIP expenses being recovered from those customer classes.[223]

156. The Department proposed calculating the CCRC by dividing the Company's proposed test year CIP expenses of $141,177 by the Department's recommended sales forecast of 5,460,873 dekatherms.[224] It is noted that the ALJ has proposed that the Commission adopt the Department's sales forecast in earlier findings.

157. Using the Department's recommended volumetric allocation method, CIP expenses would be recovered on an equal per volumetric unit basis for all customer classes and would not result in the differing customer class recovery rate, as is the case under the Company's proposal. In addition, the Department's recommended CCRC is approximately 4 percent less than the Company's approved CCRC.[225]

158. Great Plains did not show that its proposed revenue allocation method is a reasonable way to minimize inter-class subsidization. The volumetric allocation method offers a better match between the customer classes that received net benefits from Great Plains' CIP in 2003 and the recovery of CIP cost from those customer classes than the Company's proposed revenue allocation method. The volumetric allocation method offers a better opportunity to minimize inter-class subsidization and the ALJ recommends that the Commission adopt this approach.

Principles of Rate Design

159. An important aspect of reasonable rates is their design.[226] After the Commission determines the utility's revenue requirement, how those requirements will

[221] Department Ex. 65, Minder Direct, Vol. 1, at 9-10.
[222] Department Ex. 65, Minder Direct, at 10.
[223] Department Ex. 65, Minder Direct, Vol. 1, at 12.
[224] Department Ex. 65, Minder Direct, Vol. 1, at 13.
[225] Department Ex. 65, Minder Direct. Vol. 1, at 13-14.
[226] *See* Minn. Stat. § 216B.03 (2004).

be paid by customers must be established. Rate design is the application of revenue requirements to customer classes.

160. The Commission's design of rates is a largely quasi-legislative function. The application of proportional distribution of the revenue requirement among customer classes involves policy decisions that are guided by fundamental principles of rate structure. The preference to eliminate cross-subsidization, for example, may be balanced against drastic changes in the cost of natural gas to particular rate classes. The Commission has used the following principles in its rate design decisions:

> Rates should be designed to provide the Company a reasonable opportunity to recover all prudently incurred costs, including costs of attracting capital. These rates, when matched to test-year customer counts and sales projections, should allow the Company a reasonable opportunity to collect its revenue requirement.
>
> Rates should be designed to promote an efficient use of resources. As such, they should reflect the costs that classes of customers impose upon the system.
>
> Rates and conditions of service should provide a reasonable continuity with the past. Rate-design changes should be reasonable and, to the extent possible, gradual to prevent drastic impacts on existing customers.
>
> Rates should be understandable and easy to administer.[227]

<u>Customer Cost of Service Study</u>

161. In preparation for this rate application, Great Plains prepared a customer cost of service study (CCOSS). The CCOSS analyzed Great Plains' administrative and operating costs and attempted to associate identifiable costs with the particular class of customer triggering the cost. As measured by the CCOSS, the basic service charge for residential customers would need to be $19.67 to accurately reflect the residential customers' fixed cost responsibility.[228] Following the results of the CCOSS, Great Plains proposed to alter its revenue apportionment among the customer classes.[229] The Company sought to "group the class rates of return more closely about the overall system return while taking into account customer impacts and the ultimate goal of combining the distribution rate components currently applicable in the three rate areas served by the Company."[230]

162. The proposed revenue increase was apportioned by first allocating the overall increase of 3.83% to the Firm General Service class, 3.00% to the Small Interruptible classes, 2.50% to the South-13 Large Interruptible class, with the remainder allocated to the residential class.[231] This resulted in an average increase for

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[227] Department Ex. 70, Bonnett Direct, at 7.
[228] *See* Department Ex. 70, Bonnett Direct, JB-7.
[229] Company Ex. 21, Aberle Revised Direct, at 4.
[230] Company Ex. 21, Aberle Revised Direct, at 7.
[231] Company Ex. 21, Aberle Revised Direct, at 7. The rate classes applicable in the Company's three rate areas (Crookston, North 4 and South-13) include (1) Residential Service available for the domestic use of

the residential class of 4.61%.[232] In particular, the Company's proposed revenue apportionment as applied to its rate classes is as follows:

Class	Proposed Revenue Apportionment
Residential	47.26%
General Service	25.75%
Small Volume Interruptible	11.41%
Large Volume Interruptible	14.72%
Small Transportation	0.44%
Large Transportation	0.42%

[233]

163. Great Plains' initial filings failed to reflect the Commission approved phase-in of the Company's North 4 and Crookston rate areas. This consolidation was ordered by the Commission in Docket No. G004/GR-02-1682.[234] In order to reflect this consolidation in its proposed revenue apportionments, in Company Exhibit 22 Great Plains set out the following adjustments:

> Exhibit No. __(TAA-3) provides the revised increases by rate area that result from limiting the phase-in to the Crookston and North 4 rate areas in schedules identical in form to Statement E pages 1 and 2 and Schedule E-1 pages 1 through 18. The workpapers supporting the revised rate calculations are also included in Exhibit No.___(TAA-3).
>
> Exhibit No.__(TAA-4) provides a summary of the revenue allocation process proposed by the Company as adjusted to reflect the phase-in of only the

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natural gas on a firm basis; (2) Firm General Service available for the commercial use of natural gas on firm basis: (3) Small Interruptible Sales Service available for the gas used on an interruptible basis by customers with annual requirements up to 20,000 dk; (4) Large Interruptible Sales Service available for the gas used on an interruptible basis by customers with annual requirements greater than 20,000 dk; (5) Small Interruptible Transportation Service available for customers, with annual interruptible requirements up to 20,000 dk, transporting third-party gas on the Company's distribution system; and (6) Large Interruptible Transportation Service available for customers, with annual interruptible requirements greater than 20,000 dk, transporting third-party gas on the Company's distribution system.

[232] The Company's proposed revenue allocation indicates an increase in the residential class return from –4.54% to 6.36%; an increase in the firm general service class return from 4.41% to 11.86%; an increase in the small interruptible class return from 24.13% to 32.14% and an increase in the large interruptible class return from 10.33% to 16.77%. Company Ex. 21, Aberle Revised Direct, at 8.

[233] Company Initial Brief, at 88-89.

[234] Company Ex. 22, Aberle Revised Rebuttal, at 4.

Crookston and North 4 rate areas as approved in Docket No. G004/GR-02-1682. The 1st four columns entitled "1st Step of Allocation Process" show the revenue allocation described above plus the change due to the Company's proposed reallocation of the base CIP amounts.

The next 3 columns entitled on Exhibit No. ___ (TAA-4) "Modified Phase 1" show the proposed increase in revenue, resulting total revenues and the resulting percentage of total revenues represented by each rate class and each rate area. As shown, the Phase 1 increase reflects the increase associated with this rate case, the reallocation of CIP and the continuation of the consolidation of the Crookston and North 4 rate areas. It is this component of the Company's proposal i.e., continuation of the consolidation of the Crookston and North 4 rate areas that is being revised. As noted by Mr. Bonnett, the Company erroneously consolidated all three rate areas in its original proposal.

Consistent with the Company's original proposal, Great Plains proposes to implement the Phase 1 rates upon final disposition of this rate case. The final 4 columns of Exhibit No. ___ (TAA-4) entitled "Modified Phase 2" show the proposed increase in revenue, resulting total revenues, the resulting percentage of total revenues represented by each rate class and each rate area and the percent of cost represented by the Phase 2 rates that Great Plains proposes to implement 18 months after the Phase 1 rates are implemented. Only the Crookston and North 4 rate areas will be affected by the Phase 2 changes.[235]

Basic Service Charge

164. Based on its CCOSS, Great Plains proposed increasing the amount of fixed charges recovered under certain rate schedules to move toward a fully compensatory fixed charge rate. The basis for the increased amounts proposed to be collected though the Basic Service Charges is the customer component identified in the CCOSS. The Company proposed the following Basic Service Charges in this case:

Class	**Current Monthly Change**	**Proposed Monthly Charge**
Residential	$5.50	$8.00
Firm General Service < 500 Cubic Feet per hour	$20.00	20.00
Firm General Service > 500 Cubic Feet per hour	$20.00	25.00
Small Interruptible - Sales	$100.00	125.00
Small Interruptible - Transport	$175.00	175.00
Large Interruptible - Sales	$200.00	200.00
Large Interruptible - Transport	$250.00	250.00

[236]

[235] Company Ex. 22, Aberle Revised Rebuttal, at 5-6.
[236] Company Ex. 21, Aberle Revised Direct, at 9.

Basic Service Charge – Residential Customers

165. As a general principle, the Department agreed with Great Plains that a residential customer charge should move closer to cost gradually over time.[237] When weighed against the need for recovery of costs, the proper apportionment across customer classes, the avoidance of rate shock, and the ease of understanding billings, the Department concluded that increases to the basic service charge would be inappropriate.

166. The Department noted that approximately eight months prior to this rate case being filed, residential Crookston customers experienced a nearly 41 percent increase in their monthly basic service charge with North 4 and South-13 residential customers receiving approximately 134 percent increase in their monthly basic service charge.[238] The proposed increase, the Department maintains, necessarily constitutes a drastic increase.[239]

167. By the Department's calculation, increasing the monthly basic service charge an additional 45 percent means that residential customers would face an increase of approximately 240 percent over a two-year period ($8.00 - $2.35 = $5.65/$2.35 = 240 percent).[240] The Department considers such a drastic increase to be unreasonable.[241]

168. Great Plains cited the Commission's approval to increase residential customer charges in a recent case as recognition that a gradual movement towards actual costs has several tangible benefits for customers. In that matter, the Commission stated:

> [C]ustomer charges play an important role in the rate structure. They reduce utilities' capital costs by ensuring baseline levels of revenue, thereby reducing consumers' rates. They help mitigate rate volatility between seasons by recovering some fixed costs during the low-usage, summer months. They promote equity by ensuring that the rate structure does not shift the full system-costs imposed by low-usage and seasonal customers to normal-usage, high-usage, and year-round customers. And to do these things effectively, customer charges must be adjusted occasionally to reflect changes in overall costs.[242]

169. While noting that another utility had received support from the Department (in a settlement) for an increase of the basic service charge to $8.00, Great Plains did not note that the Commission rejected the request for that amount of service charge,

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[237] Department Ex. 70, Bonnett Direct, at 21.
[238] *Id.*
[239] *Id.*
[240] Department Ex. 71, Bonnett Surrebuttal, at 10.
[241] *Id.*
[242] ***In the Matter of an Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Natural Gas Service in the State of Minnesota**,* Docket No. G-002/GR-04-1511, Order Accepting And Modifying Settlement And Requiring Compliance Filings at page 7 (August 11, 2005).

allowing instead a basic charge of $6.50.[243] This $1.50 increase was the first obtained by that utility since 1992. Consistent with prior Commission orders, the ALJ finds that allowing a significant increase from the current $5.50 residential customer service charge, so soon after a large jump in that charge, would constitute rate shock.

<u>Basic Service Charge – Firm General Service Customers</u>

170. The Department noted that on January 14, 2004, Crookston firm general service customers experienced an approximately 513 percent increase in their monthly basic service charge whereas North 4 and South-13 firm general service customers received an approximately 851 percent increase in their monthly basic service charge.[244] The Department recommended that the monthly basic firm general service charge remain at its current rate to avoid a drastic increase in the charge.[245] The same analysis for residential customers applies to firm general service customers. Rate shock would occur with additional increases to the basic charge on top of the recent increases, as noted by the Department.

<u>Basic Service Charge – Interruptible Customers</u>

171. Interruptible customers experienced a level of increase in their monthly basic service charge similar to that of both the residential and firm general service customers. Interruptible Crookston customers experienced an approximate increase of 333 percent while the North 4 and South-13 interruptible customers experienced an approximate increase of 889 percent.[246] As with the other two classes, any additional increase to the basic service charge to the interruptible customers at this time would constitute rate shock.

<u>Apportionment</u>

172. Great Plains' revision of its apportionment figures shows that most rate classes in the North 4 and South-13 rate areas will experience double-digit increases to their non-gas costs under Great Plains' proposed revenue allocation.[247] All of these totals are based on Great Plains' requested revenue deficiency. To the extent that the deficiency is reduced by the Commission, those increases will be reduced proportionally. The total non-gas increases to the North 4 and South-13 rate areas are 23.30 and 21.80 percent, respectively.[248] The Department maintains that these increases will result in customer confusion and/or rate shock.[249] The Department recommended that the current rate design approved by the Commission in an Order

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[243] ***ITMO an Application by CenterPoint Energy Minnegasco, a Division of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota***, Docket No. G-008/GR-04-901 (Order Accepting and Modifying Settlement and Requiring Compliance Filing issued June 8, 2005).
[244] Department Ex. 70, Bonnett Direct, at 23.
[245] *Id*.
[246] Department Ex. 70, Bonnett Direct, at 24..
[247] Company Ex. 22, Aberle Revised Rebuttal, at 4.
[248] Department Ex. 72, Bonnett Supp. Surrebuttal, at 4.
[249] Department Ex. 72, Bonnett Supp. Surrebuttal, at 3.

dated January 16, 2004, be maintained. In the alternative, the Department suggested that an across-the-board increase of 3.83 percent for all customer classes would meet the revenue apportionment needs of Great Plains, without causing customer confusion or rate shock.[250]

173. Great Plains maintained that its proposed apportionment of revenue responsibility among its customer classes is based on the results of the CCOSS and was designed to more closely align cost recovery with cost causation.[251] The CCOSS showed small and large interruptible rates to be above fully distributed embedded cost and residential and firm general service rates to be below embedded cost.[252]

174. Great Plains' customers experienced a reallocation in the prior rate case to more closely align cost recovery with cost causation. The ALJ considers the Commission's prior rulings regarding rate shock and customer confusion to be controlling in this matter. This is particularly true given the phase-in recommendation, discussed below. The Department's across-the-board proposal for distributing responsibility for revenue deficiencies is the more reasonable approach under the circumstances presented in this matter.

Phase-in Period

175. Great Plains has proposed an immediate adjustment to rates to reflect the first phase of Commission-approved alignment of the Company's North 4 and Crookston rate areas. Great Plains maintains that this adjustment is required to meet the consolidation that was ordered by the Commission in Docket No. G004/GR-02-1682.[253] The phase-in does not affect Great Plains' overall revenue to be received but may affect the percentage increase or decrease that some customers will pay relative to other customers.[254]

176. The Department expressed concern that the immediate phase-in, coupled with the rate increase to be approved, would result in customer confusion and rate shock. The Department proposed that the first phase of the consolidation of rates for the Crookston and North-4 rate areas not begin until 18 months after implementation of final rates in this proceeding. The second phase, which would result in complete consolidation of the Crookston and North 4 rate areas, would occur 36 months after implementation of final rates in this case.[255]

177. The phase-in plan was designed to move rates toward cost without causing rate shock. While the Department emphasizes the importance of gradual rate

[250] Department Ex. 70, Bonnett Direct, at 18.
[251] Company Initial Brief, at 87-91 and the citations to the record therein; *see also* Company Ex. 2, Revised Petition, Statement E, Schedule E-2.
[252] Great Plains' IB at pages 87-89 and the citations to the record therein; *see also* Revised Petition at Statement E, Schedule E-2.

[253] Company Ex. 22, Aberle Revised Rebuttal, at 4,
[254] Tr. Vol. 4, Bonnet, at 432..
[255] Department Ex. 70, Bonnett Direct, at 17.

increases, the proposed resetting of the start date unduly delays the alignment of rates that the Commission has determined to be just and reasonable. Should the Commission accept the adjustments to Great Plains' revenue deficiency that are proposed in this Recommendation, neither rate shock nor customer confusion will result from an immediate initiation of phase 1.

S. Nonrate Issues

178. The Department proposed that Great Plains be required in its next rate case to separately include transportation customers in its CCOSS. The Department noted that Great Plains had done so in its last rate case (Docket No. G004/GR-02-1682).[256] Great Plains included separately transportation customers in its CCOSS; however, the Company did not do so in the current rate case. Since the Company separately included transportation customers in the rate design, it would be helpful to include them separately in the CCOSS. Doing so would allow comparison and would assist with ensuring the reasonableness of the Company's proposed rates. Therefore, the Department recommends that Great Plains separately include the transportation classes in the CCOSS in the Company's next general rate case. Great Plains agreed with the proposal.[257] The ALJ recommends that the next CCOSS separately identify transportation customers.

179. Although the Company has multiple rate areas with different rates, it filed a single CCOSS for the entire company. The Commission's approval of the Company's increase in the last rate case was based on a CCOSS produced on a total of Great Plains-MN costs for the various customer classes.[258] In response to Department requests for discovery for information broken out by rate area, Great Plains indicated that the information was unavailable. The Department maintains that the failure to maintain this data renders cost data review on a rate-area-by-rate-area basis to be impossible. The Department maintains that this information is necessary to determine whether the individual rate areas are paying for the costs they impose upon the system. For these reasons, the Department recommends that the Company provide a CCOSS for each rate area as well as a CCOSS for the entire company in its next general rate case.[259]

180. Great Plains asserted that the costs underlying the CCOSS are not maintained on the Company's books in a manner that would readily allow a separate CCOSS to be developed for each rate area.[260] The benefit of having the CCOSS broken out by rate area is offset the need to introduce additional divisions of the corporate allocation factors. The additional time and expense to prepare the CCOSS in this manner is not likely to provide sufficient benefits in more accurate rate setting. The costs associated with providing a CCOSS for each rate area are simply not justified.

[256] Department Initial Brief, at 144.
[257] Company Initial Brief, at 86-87.
[258] Company Ex. 22, Aberle Revised Rebuttal, at 3.
[259] Department Ex. 70, Bonnett Direct, at 5-6; Tr. Vol. 4 at 429 (Bonnett).
[260] Company Ex. 22, Aberle Revised Rebuttal, at 3.

Consistent with these circumstances, the ALJ recommends that the Commission allow Great Plains to rely upon a single CCOSS for Great Plains' future rate setting.

Extensions Review

181. In 1995, the Commission directed that the Department investigate every gas utility company's service extension-related additions.[261] The Commission wanted the following issues addressed:

1. that LDCs [local distribution companies] are applying their tariffs correctly and consistently,
2. that they are appropriately cost and load justified, and
3. that wasteful additions to plant and facilities are not allowed into rate base.[262]

182. The Department investigated Great Plains' extensions, noting that the Commission has approved the following types of service extensions:

a. Free Footage Allowance – This type of extension is used when the number of feet of main line extensions and the number of feet of service line extensions are within the free footage allowance. The length of the allowance is not "free" per se, as its costs are included in base rates, but is offered for an extension without additional funding from that customer. Any extension beyond the free footage allowance would require a contribution in aid of construction (CIAC) by the customer in order to receive service, unless it is determined that the anticipated revenue from that customer is sufficient to prevent an undue burden on existing customers.

b. Economically Feasible – This type of extension requires a showing that the extension is cost/load justified. For example, Northern States Power Company d/b/a Xcel Energy has a specific formula listed in its gas tariff to determine whether a project is economically feasible.

c. New Area Surcharge Tariff – This surcharge is applied to an area that has not previously received gas service, when the extension is <u>not</u> economically feasible and the customers in the newly piped area agree to pay a surcharge ensuring that these new customers are not unduly subsidized by other (current) customers.[263]

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[261] Docket No. G999/CI-90-563 (*Order Terminating Investigation and Closing Docket* issued March 31, 1995).
[262] DOC Ex. 66, Minder Direct, Vol. 2, BJM-9, at 1-2.
[263] Department Ex. 66, Minder Direct, at 3.

183. The Department determined that of the three primary types of extensions, Great Plains uses a free footage allowance for most customers, with a per foot charge for excess line beyond the footage allowance or beyond the standard meter location. Great Plains also uses an economic feasibility method for main lines for non-residential firm customers.[264] The Department's investigation addressed the issues that the Commission had identified in its 1995 Order, including:

- Should the "free" footage or service extension allowance include the majority of all new extensions with only the extremely long extensions requiring a customer contribution-in-aid-of-construction (CIAC)?

- How should the LDC determine the economic feasibility of service extension projects and whether the excess footage charges are collected?

- Should the LDC's service extension policy be tariffed in number of feet without consideration to varying construction costs among projects or should the allowance be tariffed as a total dollar amount per customer?

- Is the LDC's extension charge refund policy appropriate?

- Should customers be allowed to run their own service line from the street to the house (or use an independent contractor) if it would be less expensive than having the utility construct the line?

- Should the LDC be required to offer its customers financing for service extension charges? This could be offered as an alternative to paying extension charges in advance of construction.[265]

184. In its response to the Commission's free footage question, Great Plains stated that the free footage or service extension allowance should include the majority of all new extensions, with only the extremely long extension requiring a customer CIAC. Great Plains also stated that its authorized extension policy for a residential customer provides for a main line allowance up to 100 feet per customer and a service line allowance equal to the lesser of 3 feet beyond the corner of the premise facing the main or 75 feet. In addition, the Company stated that service extensions in excess of these prescribed allowances are charged to the customer requesting service. The Company asserted that these procedures provide for economic gas extensions.[266]

185. Great Plains stated that it determines the economic feasibility of service extension projects based on the specific construction requirements, including the appropriate location of the extended line, the customer's gas requirements, and the footage allowances described above. Great Plains also stated that footages required in excess of those prescribed in tariff are charged to the customer on a time and material

[264] *See* Department Ex. 66, Minder Direct, Vol. 2, at 4.
[265] Department Ex. 66, Minder Direct, BJM-9, at 5
[266] *See* Company Ex. 4, Aberle Supp. Direct, at 6; Department Ex. 66, Minder Direct, Vol. 2, at 10.

basis. Great Plains asserts that these measures properly ensure gas extensions are economic.[267]

186. The Department concluded that the policy was reasonable, although with some qualifications. For excess footage beyond the tariffed footage allowance or the standard meter location, and for the relocation of existing meters and service lines, the Department was concerned that Great Plains' proposed continuation of certain extension tariff provisions would allow the Company to charge customers based on a time and material basis, rather than an average cost per foot basis specified in tariff. [268] Great Plains did not raise any objections to the Department's conclusions.

187. On the per foot/dollar amount question, Great Plains maintained that the footage allowance provided in its current tariff is preferable to an allowance tariffed as a dollar amount per customer allowance because the footage allowance more accurately reflects the true costs of providing the extension.[269]

188. The Department expressed a preference for the extension practice to be tariffed in the number of feet for simplicity and understandability. The free footage allowances are based on a "typical" construction length. Using a typical cost of construction (which is fully cost/load justified), the free footage option is a functional method of assigning cost that is fair and understandable to customers and is administratively efficient for the utility. Customers are all treated in the same identifiable manner as described in the utility's tariffs. Utilities are not faced with the burden and cost of identifying the specific costs for each customer. Nevertheless, a utility continues to bear responsibility for maintaining books and records of the costs associated with extensions in order to satisfy its burden of showing that rate base expenses are reasonable during a general rate proceeding.[270] The parties appear to agree on this issue.

189. Regarding the charge refund policy question, Great Plains stated that its currently authorized policy is to not provide refunds once a contribution has been collected from a customer. The Company maintains that this approach has been accepted by customers and provides for ease of administration of new extensions. The Company asserted that this policy should remain as currently authorized.[271] The Department agreed with the policy. Great Plains' charge refund policy should be approved as reasonable.

190. On the customer-installed service line question, Great Plains objected to customers (or their contractors) being allowed to run their own service lines from the street to the house. As a regulated public utility, Great Plains emphasized that the Company is responsible for maintaining a safe and reliable gas system, and the Company must satisfy all codes and standards applicable to such installations. Great

[267] *See* Company Ex. 4, Aberle Supp. Direct, at 6; Department Ex. 66, Minder Direct, Vol. 2, at 11.
[268] *See* Department Ex. 66, Minder Direct, Vol. 2, at 11.
[269] Company Ex. 4, Aberle Supp. Direct, at 6; Department Ex. 66, Minder Direct, Vol. 2, at 11.
[270] Department Ex. 66, Minder Direct, Vol. 2, at 11.
[271] Company Ex. 4, Aberle Supp. Direct, at 7 Department Ex. 66, Minder Direct, Vol. 2, at 13.

Plains asserted that system reliability could be unnecessarily threatened by outside installers. Great Plains also expressed concern that additional costs would be incurred to ensure that such construction is consistent with the Company's obligation to provide safe and reliable service.[272] The Department agreed with the Company's concerns.

191. On the Company-financing question, Great Plains noted that it does not offer financing options for service extensions. The Company maintained that, as a small utility, it should not be required to take on the additional risk associated with providing financing options.[273] The Department agreed that each utility should identify whether or not financing options are necessary for their particular customer types and what are the most appropriate financing options to offer. The Department also agreed that utility financing should not be mandatory for all utilities. Great Plains' decision to not offer financing options is reasonable.[274]

Extension Tariff Application

192. In addition to the six items addressed above, the Commission's Order issued on March 31, 1995 in Docket No. G999/CI-90-563, identified three concerns to be examined.[275] The first concern was that Great Plains make a showing of correct and consistent application of the Company's tariff since its last rate case,

193. Great Plains provided the information and accompanying narrative required by the Commission in its *Order Accepting Rate Case Filing as of Future Completion Date and Suspending Rates* issued on November 1, 2004 in Docket No. G004/GR-04-1487. Great Plains reviewed the total population of main line and service line extensions installed to provide service to new customers during the period of October 9, 2003 through October 1, 2004. The Company identified 178 service line extensions and 19 main line extensions that were installed to provide service to new customers during that period.[276]

194. Based on the Company's examination of its extension records for this period, Great Plains stated that it identified some inconsistent applications of its extension tariff. Specifically, the Company stated that it found 18 errors with respect to service line footages during the period of October 9, 2003 and October 1, 2004, which resulted in a total of $38 in pipe materials that should have been charged to customers. Great Plains also stated that any customer contribution requirements associated with a main line extension were determined in accordance with the Company's approved extension tariff. In addition, Great Plains asserted that its employees now have a better understanding of extension policies and are consistently applying them.[277]

[272] Company Ex. 4, Aberle Supp. Direct, at 7 Department Ex. 66, Minder Direct, Vol. 2, at 13.
[273] Company Ex. 4, Aberle Supp. Direct, at 7 Department Ex. 66, Minder Direct, Vol. 2, at 15.
[274] Department Ex. 66, Minder Direct, Vol. 2, at 15.
[275] Department Ex. 66, Minder Direct, Vol. 2, at 15.
[276] Company Ex. 4, Aberle Supp. Direct, at 8, TAA-2; Department Ex. 66, Minder Direct, Vol. 2, at 17.
[277] Company Ex. 4, Aberle Supp. Direct, at 8; Department Ex. 66, Minder Direct, Vol. 2, at 18.

195. The Commission also imposed requirements on Great Plains regarding to extensions in Ordering Paragraph Nos. 1(b) through 1(d) of its *Order Accepting and Adopting Settlement* issued on October 9, 2003 in Docket No. G004/GR-02-1682. These requirements include locating the property line on all drawings, measuring the relevant footage, showing the excess footage calculation, keeping records on the process for applying the tariff, and billing for excess footage charges higher than $3.00. The Department investigated Great Plains' compliance with the *Order* and found that in nine service line projects, the Company undercharged customers by a total of approximately $32 in costs that were not charged to extension customers per the tariff.[278]

196. Great Plains identified the same nine service line extension errors and nine additional service line extension errors in its research into the subject.[279] For all of these service line extensions, Great Plains calculated that the errors resulted in a total of $38 in costs that were not charged to extension customers per the tariff.[280] The Department noted that the number of errors appeared to be declining and the Company applied its service line extension tariff more accurately and consistently later in the period examined.[281]

197. Great Plains undertook to develop a standard form to be completed for each main and service line extension that will assist personnel in correctly applying the tariff and provide information necessary to review each extension more efficiently. The Company also committed to continuing ongoing communication and education processes with its personnel to ensure familiarity with the tariff and to ensure consistent and accurate tariff application for all service extensions.[282] With these assurances, the application of tariffs to service line extensions can be found to be reasonable, with any demonstrated noncompliance dismissed as *de minimis*.

198. The Department did express concern over Great Plain's calculation that no customer contribution was required for the installation of 1,436 feet of main line to serve a new car wash/pet supply facility, whose gas requirements were estimated at 1,500 dk per year. Great Plains followed a straight calculation of estimated annual throughput at 15 times greater of a typical residential customer, entitling the customer an extension allowance of 1,500 feet (15 times the 100 foot allowance).[283]

199. The Department objected to that calculation, maintaining that Great Plains must also calculate the incremental cost of providing the main extension. In its response to a Department Information Request, Great Plains stated that the estimated non-gas annual revenues associated with that project were $1,832.[284] However, Great

[278] Department Ex. 66, Minder Direct, Vol. 2, at 20.
[279] Company Exhibit 21, Aberle Revised Direct, TAA-2.
[280] Department Ex. 66, Minder Direct, Vol. 2, at 20.
[281] Department Ex. 66, Minder Direct, Vol. 2, at 21.
[282] Department Ex. 67, Minder Surrebuttal. at 20.
[283] Department Ex. 67, Minder Surrebuttal. at 21.
[284] Department Ex. 67, Minder Surrebuttal, at 22, BJM-S-4.

Plains also states that no cost estimate associated with the project was documented to determine if a contribution should have been required from the customer.

200. Great Plains has recognized that failing to calculate the incremental cost is not compliant with the tariff. The Company maintained that the oversight has been addressed with personnel and will be one subject of its ongoing education process. Ultimately, the Department agreed with the result of the Company's cost contribution conclusion (that no customer contribution was required) but maintained that future misapplication of the Company's extension tariff may result adjustments in later proceedings.[285]

<u>Cost and Load Justification of Extensions</u>

201. Great Plains provided, in response to a Department Information Request, an analysis indicating that the Company's incremental average cost associated with a 100 foot main line allowance and a 75 foot service line allowance is $267. The Company's analysis also indicated that the average annual non-gas revenue collected from an average firm customer is $271.[286] The Department concluded that this analysis shows Great Plains is receiving more non-gas revenue from an average firm customer than the incremental average cost associated with the Company's tariffed main line and service line allowances. Based on this analysis, Great Plains has shown that its service related additions are appropriately cost and load justified.[287]

<u>Preventing Wasteful Additions Through Extension Practices</u>

202. Great Plains responded to a Department Information Request that the Company's gas extension policies are intended to prevent wasteful additions to plant and facilities. Great Plains also indicated that the service line and main line allowances are supported by the non-gas margin collected from the new customer. Great Plains asserted that these additional margins benefit existing customers by providing additional contributions, thereby reducing the amount required of existing customers to recover Great Plains' fixed costs.[288] Great Plains' extension practices have been shown to be a reasonable means of avoiding wasteful additions to plant and facilities.[289]

<u>Proposed Extension Tariff Changes</u>

203. Great Plains proposed to eliminate the tariff provision in Section No. 6, Subsection 4 *Service Facilities on Customer Premises* that required a reconnection charge of $160.00 whenever reinstallation was required. Great Plains explained that the provision was reflective of a change that had been proposed, but not yet approved, in Docket No. G004/M-04-1109 when this rate case was filed. Great Plains also indicated that the Company received Commission approval in September 2004, in

[285] Department Ex. 67, Minder Surrebuttal, at 22.
[286] Department Ex. 66, Minder Direct, Vol. 2, at 22; BJM-11.
[287] Department Ex. 66, Minder Direct, Vol. 2, at 23.
[288] Department Ex. 66, Minder Direct, Vol. 2, at 24, BJM-10.
[289] Department Ex. 66, Minder Direct, Vol. 2, at 25.

Docket No. G004/M-04-1109, relocating this provision to a different paragraph in the Company's General Terms and Conditions portion of its tariff.[290] Great Plains' compliance filing that contains the Commission's approved final rates and tariffs in the present docket should reflect the Commission's determinations in Docket No. G004/M-04-1109.[291]

204. In its rate case filing, Great Plains proposed to continue certain extension tariff provisions that refer to generic labor and materials rates rather than setting forth a specific charge or charges in tariff. Specifically, the Company proposed to continue a provision related to service line construction that states the following:

> Service line installation charges shall be based upon the Company's labor and material rates for any service line exceeding 75 feet or placed beyond the standard meter location.[292]

205. This language parallels that of another existing tariff provision, which states:

> When a customer requests relocation of a meter and/or service line, charges will be made at standard labor and material rates.[293]

206. The Department objected to these Company tariff provisions, asserting that the tariff should be changed to include specific per foot charges, rather than a generic reference to charges for labor and materials. The Department acknowledged that one of the tariffs is already Commission-approved. But the Department maintains that customer clarity and convenience are impaired by this tariff, and the cost mechanism is not legally supported.[294]

207. The Department cited the general rate case procedure of Minn. Stat. § 216B.16 as requiring analysis of costs as well as revenues in the setting of new rates, and sets forth a general rate change process. There are a few express statutory exceptions to the process of changing rates as part of a general rate case such as the Purchased Gas Adjustment and Conservation Improvement Program statutes.[295] Absent a statutory exception relating to costs for material and labor for main line and service line extensions or for the relocation of existing meters and service lines, the Department maintains that a per foot charge must be used.[296]

208. In its Rebuttal Testimony, Great Plains agreed with the Department's recommendations concerning tariff per foot costs, as described above. Great Plains

[290] Department Ex. 66, Minder Direct, Vol. 2, at 24-25, BJM-10.
[291] Department Ex. 66, Minder Direct, Vol. 2, at 24.
[292] *See* Section No. 6, Original Sheet No. 6-12, Subsection 4(a)(2) *Service Facilities on Customer Premises*. Department Ex. 66, Minder Direct, at 25.
[293] *See* Section No. 6, Original Sheet No. 6-13, Subsection 4(c) *Service Facilities on Customer Premises*. Department Ex. 66, Minder Direct, Vol. 2, at 25-26.
[294] Department Ex. 66, Minder Direct, Vol. 2, at 25.
[295] *See* Minn. Stat. § 216B.16, subds. 6b and 7.
[296] Department Ex. 66, Minder Direct, Vol. 2, at 28.

stated that the costs will be developed and tariff language prescribing these costs will be proposed in the compliance filing in the present docket.[297] Based on that agreement, the ALJ recommends that the specific tariff issues not agreed to or addressed in subsequent findings be addressed in the compliance filing or a separate miscellaneous tariff filing.

Purchased Gas Adjustment Recalculation

209. Great Plains proposed a tariff change increasing the Purchased Gas Adjustment (PGA) to $.10 per dk from its existing level of $.030 per dk. The Company's rationale for this proposed tariff change is that a higher threshold for determining when the PGA rate will be adjusted is appropriate given the higher magnitude of gas costs.[298] The Department objected, citing Minnesota Rules part 7825.2700, subp. 3, which states in pertinent part:

> The adjustment per Mcf, Ccf, or Btu must be applied to billings whenever the change in commodity-delivered gas cost and demand-delivered gas cost exceeds $0.03 per 1,000,000 Btus.

210. No basis for changing the tariff has been cited that would exempt the PGA from the application of the rule. Great Plains acknowledged that the PGA rate should not be adopted at this time.[299] The ALJ recommends that the proposed change to the PGA tariff be rejected.

T. Concepts to Govern

211. The parties to this proceeding have taken significantly different approaches to how the revenues and expenses of Great Plains should be calculated to arrive at just and reasonable rates. In some instances, the underlying cost numbers are not readily apparent from the record, resulting in an inability to set out a spreadsheet identifying the precise numbers recommended by the ALJ. It is the intention of the ALJ that the concepts set forth in the Findings and Conclusions should govern the mathematical and computational aspects of the Findings and Conclusions. Any computations found to be in conflict with the concepts expressed should be adjusted to conform to the concepts expressed in the body of this Report.

Based on the foregoing Findings, the Administrative Law judge makes the following:

CONCLUSIONS

1. The Administrative Law Judge and the Minnesota Public Utilities Commission and have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. § 14.50 and Minn. Stat. Ch. 216B.

[297] Department Ex. 67, Minder Surrebuttal, at 19.
[298] Department Ex. 65, Minder Direct, Vol. 1, at 34, BJM-8.
[299] Company Initial Brief, at 107.

2. Any of the foregoing Findings which contain material which should be treated as a Conclusion are adopted as Conclusions.

3. The sales forecasts relied upon by Great Plains have not been shown to reasonably predict the sales volumes for the 2005 test year. The Department has demonstrated its approach to forecast volumes for that test year is a reasonable prediction upon which the Commission can rely in setting rates in this matter.

4. Applying the Department's approach to sales volumes results in an estimated sales revenue adjustment of $1,291,484 (not including late payment fees and other revenue, discussed elsewhere), and an increase of $1,060,457 in O&M expenses.

5. The parties agreed that 2004 actual data will be used to determine other operating revenue, resulting in an increase in operating revenue by $5,761.

6. The capital structure agreed to by the parties is reasonable. The Department has demonstrated that a rate of return on equity of 9.72 percent is reasonable. The Department has demonstrated that an overall rate of return of 8.96 percent is reasonable. The ROE calculation results in an adjustment of $117,598 to Great Plains' revenue requirement.

7. The Department has demonstrated that an adjustment is needed to the allocation of payroll and benefits costs between regulated and non-regulated business activities as measured by Great Plains' time study, resulting in an adjustment of $49,034.

8. The Department has demonstrated that an adjustment is needed to the allocation of corporate costs between MDU, MD Utilities, and Great Plains-MN. The incentive compensation assigned to Great Plains-MN includes $62,059 in unallowable incentive compensation. It is appropriate to reduce the allocation by that amount.

9. The Department has shown that Great Plains' allocation of test year Administrative and General ("A&G") expenses is overstated and an adjustment is needed. The Department's recommended adjustment to A&G expenses of $149,945 must itself be reduced for the insurance expense properly allocated to Great Plains from MDU and/or MD Utilities. Great Plains has demonstrated that its costs for insurance were properly allocated. Great Plains has also shown that its GIS expense is properly allocated. It is appropriate to reflect allowable costs of $5,386 for allocated GIS salary expense in the overall allocation adjustment and to include $246,404 for the allocated GIS investment in the rate base.[300]

10. The parties agreed that bad debt expense would be based on a five-year average of write-offs to revenue using actual 2004 revenues, resulting in a reduction of test year expense by $15,239.

[300] The GIS reference is included for clarity, since the numbers may already be reflected in the proposed adjustments.

11. The parties agreed that all but $206 of the total advertising costs meets the criteria set forth in Minn. Stat. § 216B.16, subd. 8, resulting in a reduction of test year expense by $206.

12. The parties agreed that an adjustment was appropriate to the calculation of test-year late payment fees, that results in an increase in revenue to Great Plains of $53,762.

13. The parties agreed that the overall amount of $308,450 for rate case expense was reasonable. The Department demonstrated that applying an allocation factor to assign a portion of the costs to non-regulated business operations is appropriate. The Department demonstrated that an adjustment of $18,303 to the rate case expense is appropriate.

14. Great Plains has demonstrated that amortization of its approved current rate case expenses over a period of three years is appropriate.

15. Great Plains has not shown that inclusion of approved prior year rate case expenses is appropriate. Consistent with prior Commission orders, Great Plains has shown that receiving an offset against any refund for interim rate overcharges is within the Commission's discretion.

16. Great Plains has not shown that an adjustment is appropriate for amounts not approved for prior year rate case expenses.

17. The Department has shown that it is appropriate to use the volumetric method in recovering CIP expenses. Great Plains has not shown its proposed revenue allocation method for recovering CIP expenses to be appropriate.

18. Department has demonstrated that an increase in the residential basic charge to $8.00 per month and the similar increases in other rate classes would result in rate shock to customers. It is appropriate, consistent with the Commission's principles regarding rate shock, to retain the residential basic service charge at $5.50 per month and that the corresponding charge to the other rate classes also remain unchanged.

19. The Department has demonstrated that retaining the existing apportionment of Great Plains' revenue requirement across customer classes is appropriate to avoid rate shock and customer confusion.

20. Great Plains has demonstrated that adjusting rates across the North 4 and Crookston rate areas is appropriate and will not result in rate shock or undue customer confusion.

21. The record in this matter shows that Great Plains will experience a revenue shortfall of approximately $400,000, constituting a revenue requirement increase of approximately 1.2%, and Great Plains is entitled to recover this revenue shortfall through an adjustment of natural gas rates in the manner described in the Findings and

Conclusions above. Such an adjustment results in just and reasonable rates that are in the public interest within the meaning of Minn. Stat. § 216B.11.

22. The rate finally ordered by the Commission may be compared to the interim rate set in the Commission's November 1, 2004 Order, and a refund be ordered to the extent that the interim rate exceeds the final rate, in the exercise of the Commission's discretion.

23. In the event a refund is ordered, it would be appropriate for the Commission to consider a request to offset unrecovered prior year rate expenses that have been previously approved against any amount ordered as a refund of interim rates.

Based on the Findings and Conclusions above, **IT IS RECOMMENDED** that the Public Utilities Commission issue the following:

ORDER

1. Great Plains is entitled to increase gross annual revenues in accordance with the terms of this Order.

2. Within 30 days of the service date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for annual periods beginning with the effective date of the new rates, and the rate design decisions contained herein. The Company shall include proposed customer notices explaining the final rates. Parties shall have 14 days to comment.

3. (If the Commission orders an Interim Rate Refund) within 30 days of the service date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties in this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein. Parties shall have 14 days to comment.

Dated this 4th day of November, 2005.

_/s/ Richard C. Luis_____________
RICHARD C. LUIS
Administrative Law Judge

Reported: Shaddix and Associates
Transcripts Prepared, Four Volumes

MEMORANDUM

At the time the Commission issued the ***Merger Order***, assurances were made regarding the post merger operation of Great Plains. The Commission noted that:

> On cost and rate issues, the Department considered the Stipulation and Agreement, coupled with supplementary assurances agreed to by petitioners, adequate protection for Minnesota ratepayers. It did not believe the merger posed any financial risk to either of the two petitioners. In fact, the Department believed that if the merger had any effect on Great Plains' cost of capital, a critical component of the cost of service, it would reduce that cost.
>
> * * *
>
> For similar reasons, the Department found that the merger would not compromise this Commission's ability to regulate the company or its ability to protect Minnesota ratepayers. Great Plains will provide service as a free-standing MDU operating division headquartered in Fergus Falls. Its books will continue to reflect only its own financial transactions and condition.[301]

In practice, Great Plains' books do not "reflect only its own financial transactions and condition." The untangling of the interwoven transactions between MDU, MD Utilities, and Great Plains, to assure that Minnesota ratepayers are not subsidizing other corporate costs and the cost of non-regulated business operations has contributed to the length and complexity of this proceeding.

The guiding principles followed to determine which of the allocated costs are allowable are set out in the conditions of the ***Merger Order***. Any increases in costs (outside of the normal adjustments for inflation) from the costs allocated to Great Plains must be shown to be for reasons not arising from the merger. Thus, replacement of Great Plains officers and employees, by officers and employees of MDU or MD Utilities must be affirmatively shown to be reasonable, both in duties performed and costs calculated for allocation.

The Department has proposed, and the ALJ accepted, an alternative cost approach for which Great Plains has not made the required showing. The alternative calculates the reasonable cost of the positions that Great Plains had prior to the merger and imputes that reasonable cost to the allowable costs in his proceeding for setting rates. For salaries allocated to Great Plains, the Department's approach arrives at an expense calculation that holds Minnesota ratepayers harmless to costs resulting from the merger, as required by the ***Merger Order***. Where Great Plains has made a showing that the allocated costs arise from post-merger business necessity (insurance and GIS expenses), the ALJ has recommended that the Commission allow the allocations. Ultimately, the Commission must determine the degree to which the conditions set forth in its ***Merger Order*** control the outcome of this rate proceeding.

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[301] ***Merger Order***, at 4.

The Commission has recently decided a matter bearing on the issue of rate shock. The ALJ accepts the Department's analysis on the rate shock issue due to both the absolute size and recent increase of the basic charges for Great Plains' customers.

R.C.L.